

**PUBLIC SERVICE ELECTRIC  
AND GAS COMPANY**

**RESPONSE TO USEPA  
APRIL 30, 1996  
REQUEST FOR INFORMATION**

**ESSEX GENERATING STATION**

**DATED: AUGUST 13, 1996**

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## **1.0 Background**

### **1.1 Introduction**

The United States Environmental Protection Agency ("USEPA") served Public Service Electric and Gas Company ("PSE&G") with a Request For Information Diamond Alkali Superfund Site, Passaic River Study Area, dated April 30, 1996 under the Comprehensive Environmental Response, Compensation and Liability Act of 1998, as amended, 42 U.S.C. Section 9601 et seq. ("Request For Information"). By this Request For Information, USEPA seeks information and records concerning industrial operations conducted at two PSE&G facilities: the former Harrison Gas Plant in Harrison, New Jersey, and the Essex Generating Station in Newark, New Jersey.

PSE&G's response to this Request For Information was originally scheduled to be provided to USEPA within thirty calendar days of receipt of same. USEPA has extended the time for the submission of this response until August 13, 1996.

PSE&G has prepared this submission as its response to the Request For Information. PSE&G submits that this submission is responsive and, further, it commits to make all relevant records referenced herein available for inspection at the USEPA's request. PSE&G wishes to apprise USEPA of certain background information to consider in connection with evaluating this

response.

Industrial operations at the Harrison Site commenced in 1902. Initially, the Site was used as a satellite storage facility for a manufactured gas plant. In 1926, construction of a manufactured gas plant was completed at the Site and commercial operations of this facility began. Base load gas manufacturing operations ceased in 1965. Thereafter, the Site was utilized as a peak-shaving facility operating on average approximately 100 hours per year. Peak-shaving operations were generally terminated after the 1986/87 winter. The gas plant has been dismantled. After operations ceased, there was no concerted effort made to preserve or maintain Plant operating records.

A steam electric generating station commenced commercial operations at the Essex Site in 1915. A substantial portion of the steam generating facility was removed from service in the early 1970s and the entire steam plant was removed from service in 1978. The steam plant was dismantled in 1990. The Site still houses a fleet of combustion turbines which generate electricity on peak demand days in the summer and winter. After steam electric generating operations ceased there was no concerted effort made to preserve or maintain Station operating records.

PSE&G has attempted in good faith to locate and review documents potentially relevant and responsive to the Request For Information. The absence of any organized records has made this task extremely difficult. This difficulty has been compounded by the long history of the operations, the nature and scope of the Request For Information and the limited period within

which to respond. This response should be considered in this context. PSE&G recognizes its continuing obligation to supplement this response if information not known or not available as of the date of this response should later become known or available to it.

Finally, PSE&G advises USEPA that this response was prepared by a team of PSE&G employees with assistance from certain external resources. A Project Manager was designated to coordinate its response to the Request for Information for each facility and each Project Manager worked with a small team including Company counsel to prepare a response for that facility. The Project Manager for each such facility is designated as the knowledgeable person for such facility and has executed the required certification.

## **1.2 Corporate History**

Public Service Enterprise Group Incorporated ("Enterprise") was incorporated in 1985 under the laws of the State of New Jersey. Its principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07101. It is a public utility holding company that neither owns nor operates any physical properties. A copy of the Certificate of Incorporation of Enterprise is produced herewith as Appendix A. Enterprise has two direct wholly-owned subsidiaries, Public Service Electric and Gas Company ("PSE&G") and Enterprise Diversified Holdings Incorporated ("EDHI"). Enterprise's principal subsidiary, PSE&G, is an operating public utility engaged principally in the generation, transmission, distribution and sale of electric energy service and in the transmission, distribution and sale of gas energy service in New Jersey. The agent for service

of process for PSE&G is E. J. Biggins, Jr., Corporate Secretary.

PSE&G was formed in 1924 by the merger, inter alia, of the Public Service Gas Company and the Public Service Electric Company. The Public Service Gas Company and the Public Service Electric Company were also New Jersey corporations organized in 1873 and 1910, respectively. Both entities were, at the time of the merger, wholly owned subsidiaries of The Public Service Corporation, a New Jersey corporation organized in 1903. PSE&G was, as a result of the merger, and remained until 1948, a wholly owned subsidiary of The Public Service Corporation. The Public Service Corporation was dissolved in 1948 and as part of the Plan for Dissolution, PSE&G became a publicly owned utility.

EDHI is the parent of Enterprise's non-utility businesses: Community Energy Alternatives Incorporated ("CEA"), an investor in and developer and operator of cogeneration and independent power production facilities; Public Service Resources Corporation ("PSRC"), which makes primarily passive investments; Enterprise Group Development Corporation ("EGDC"), a diversified nonresidential real estate development and investment business; PSE&G Capital Corporation ("Capital"), which provides debt financing on the basis of a minimum net worth maintenance agreement from Enterprise; and Enterprise Capital Funding Corporation ("Funding"), which provides privately placed debt financing.

Enterprise Form 10-K for the year ended 1995 is enclosed as Appendix A.

## **2.0 General Site Development**

Section 2.0 provides general information relating to the Essex Generation Station's ("Station" or "Essex") location, property acquisition history and Station infrastructure.

### **2.1 Site Location**

The Station is located in Newark, New Jersey on the west shore of the Passaic River immediately north of the Pulaski Skyway at a river location commonly referred to as "Point No Point" (see Figure 2.1). The street address is 155 Raymond Boulevard.

### **2.2 Site Ownership**

The lands comprising the site of the Station were purchased in a series of transactions over a number of years. Figure 2.2 presents a summary of these transactions. Available conveyance instruments are available for inspection.

### **2.3 Station Infrastructure**

Essex began operation in 1915 with four low pressure stoker boilers and two, 22,500 kilowatt ("kW") turbine/generators. In 1916, four additional low pressure stoker boilers were added. Four more low pressure stoker boilers and a 40,000 kW turbine/generator were installed

in 1918. Four more low pressure stoker boilers were added in 1919. Three identical 36,000 kW turbine/generators and eight additional low pressure stoker boilers were installed by 1924 - completing the initial phase of Station construction. As of 1924, the Station was comprised of twenty-four low pressure stoker boilers and six turbine/generators with a combined capacity of 193,000 kW. The low pressure stoker boilers were originally equipped to burn only coal.

The Station also contained electric distribution switching equipment. The switching equipment included buses, oil circuit breakers, transformers, physical disconnect switches and transmission and distribution line connections. Circa 1925, the Station became a key feeder point within the Company's then existing high voltage transmission system. To accommodate this new operation, additional switching equipment was installed.

In 1937, eight of the low pressure stoker boilers were removed and replaced with two high pressure boilers ("Nos. 25 & 26"). The two new boilers were designed to burn both coal and oil as fuel. One turbine/generator (known as "Unit No. 7") was also added. This equipment increased Station capacity by 50,000 kW. Low pressure (225 psi) exhaust steam from Unit No. 7 was not condensed but was fed to the main low pressure steam header and then directed to the existing low pressure turbine/generator units to produce an additional 70,000 kW of electricity.

In 1946, the original Unit No. 1 turbine/generator was retired along with four low pressure stoker boilers. A new 100,000 kW turbine/generator, high pressure boiler combined unit was installed in 1947. The new boiler (referred to as the "New Unit No. 1") provided steam to its

dedicated turbine/generator. This boiler was designed to burn coal, oil or gas. With the addition of the New Unit No. 1, the Station possessed its largest electric steam driven generating capacity of 320,500 kW.

A major reconstruction of the electrical switching operation was completed by 1940. Additional switching equipment was installed at the Station in 1946, 1950, 1970 and 1991 to upgrade switching operations to handle increased electric power routed through the Station for distribution to customers.

Commencing in the early 1970s, the Station began a phase-out of its steam-powered electric generation. The last steam unit was removed from service in 1978 and the steam Station was demolished in 1991.

Commencing in 1963, combustion turbine peaking units were installed at the Station to provide supplemental generating capacity during peak periods of demand. Combustion turbines are pre-fabricated, self-contained electric generating units which combust fuel (low sulfur distillate oil or natural gas) producing exhaust gases that drive a coupled turbine/generator to produce electricity. The first unit (known as "Unit No. 8") commenced operations in 1963. Four additional units were installed, three in 1971 (known as "Units Nos. 9 through 11") and a fourth in 1972 (known as Unit No. 12). As of 1972, the Station reached combustion turbine electric generating capacity of 585,333 kW (nameplate rating).

In 1980, combustion turbine Unit No. 8 was removed from service. In 1990, Unit No. 9 was replaced with a new combustion turbine unit ("New Unit No. 9") with an electric generating capacity of 90,000 kW, the same capacity as former Unit No. 9. Four combustion turbine units remain in service today with a combined total capacity of 664,333 kW (nameplate capacity).

Available engineering drawings of Station generating and auxiliary equipment are available for inspection. Figures 2.3 through 2.7 depict the layout of the Station as of 1925, 1940, 1951, 1974 and 1996.

### **3.0 Site Processes and Related Operations**

Section 3.0 provides a description of the electric generation processes as well as auxiliary and maintenance processes used at the Station over its operating life. Information relative to the raw materials used and the residuals generated is also provided.

This section has been prepared from, among other things, information contained in various available Plant records and relevant corporate history references. In addition, the Electric Power Research Institute "Power Plant Integrated Systems: Chemical Emissions Studies" has been referenced to identify and characterize many of the materials utilized and generated at the Plant.

#### **3.1 Low Pressure Turbine/Generators and Boilers**

This section presents a discussion of the electric generation process and auxiliary processes involved with the generation of electricity using low pressure boilers and turbine/generators. A process flow diagram is provided as Figure 3.1.

### **3.1.1 Process Description**

The Station's initial electric generation process began in 1915 using a combination of Babcock & Wilcox wet bottom underfeed, coal fired, low pressure stoker boilers and General Electric turbine/generator units. By 1924, twenty additional boilers and four additional turbine/generator units were installed. The six turbine/generators were all housed in the turbine building and the 24 low pressure boilers were housed in three integrated sections, without separating walls within the boiler house in sets of eight to a section. Table 3.1 provides the operating parameters for the low pressure boilers and turbine/generator units. Table 3.2 lists the raw materials used in both the generation and auxiliary processes at Essex.

Steam was generated by burning coal, fed into the boiler at the bottom of the furnace by stokers. City water was heated in the boiler to an approximate temperature of 545° F, creating steam at a pressure of 225 pounds per square inch ("psi"). City water was treated with chemicals prior to use in the boiler to prevent boiler tube internal scaling and corrosion which adversely affected boiler tube heat transfer efficiency and created the potential for boiler tube overheating. The boilers were equipped with forced draft and induced draft fans. The forced draft fans supplied air via a duct to the boiler from the bottom of the furnace. The induced draft fans at the

top of the boiler provided draft which facilitated movement of combusted (heated) gases within and through the boiler. The heated combustion gases passed around the boiler tubes to heat the boiler feedwater in the boiler tubes to produce steam. A fire brick baffle in each of the boilers forced the heated combustion gases to turn and pass around the boiler tubes several times before exiting the boiler through the stack. The residual combusted gases were exhausted to the atmosphere. This boiler design optimized heat transfer and reduced particulate emissions, as materials trapped in the combustion gases tended to drop to the furnace floor.

Low pressure steam generated in the boilers was delivered to the turbines by means of carbon steel pipelines and expanded through the turbines. Each turbine was comprised of a series of blades attached to a hardened steel shaft. Low pressure steam expanded against the turbine blades and caused the turbine shaft to rotate at a rate of 1800 revolutions per minute ("rpm"). Each generator rotor, which consisted of a hardened steel shaft and a series of copper conductors, was directly coupled to the turbine shaft and thus rotated at the same speed as the turbine. The generator rotor rotated inside a stator, consisting of a series of copper windings, which produced an electromagnetic field resulting in generation of electric power.

The steam exited the turbine under vacuum entering the water-cooled condenser located directly below the turbine. The steam was condensed, and the condensate was pumped to a surge tank from where it was gravity fed to boiler feed pumps for reuse in the electric generation process. The non-contact cooling water used to condense the process steam was withdrawn from the Passaic River through an intake canal, passed through the condenser, and discharged back to

the Passaic River via a discharge canal.

Circa 1933, oil burners were installed in the low pressure boilers. By 1949, all the remaining low pressure boilers were converted to oil, thus eliminating the use of coal stokers. Eight low pressure boilers were removed from service and dismantled in 1937, and by 1955 another eight low pressure boilers were removed from service. The remaining eight low pressure boilers continued to be available to supply steam to the low pressure turbine/generators until they were taken out of service circa the mid 1970s.

### **3.1.2 Auxiliary Processes**

This Subsection describes the ancillary processes associated with the generation of electricity using low pressure boilers including boiler water treatment, non-contact cooling of the main condensers and auxiliary equipment, and the Station's internal sewer system.

#### **3.1.2.1 Boiler Water**

The water supplied as makeup to the boilers to create steam was purchased from the City of Newark water supply. Minerals (such as calcium and magnesium bicarbonates and silica) and oxygen in city water have the potential to cause scaling and corrosion on the inner walls of boiler tubes, which in turn reduces the heat transfer efficiency of the boiler and can also lead to overheating of boiler tubes. The boiler tubes in the low pressure boilers were made of carbon

steel and were four inches in diameter. City water was initially fed to a surge tank and then gravity fed to open heaters. The open heaters were designed to drive off dissolved oxygen, which corrodes boiler tubes and Station piping systems. The removal of oxygen from the boiler feedwater significantly limited the buildup of corrosion products on the inner wall of the boiler tubes. Treatment chemicals were added to the city water in the open heaters to control boiler water chemistry and to prevent scaling and corrosion. Treatment chemicals included soda ash, caustic soda, sodium sulfate, phosphoric acid and disodium phosphate. (See Table 3.2) Typical boiler chemistry limits are provided in Table 3.3. These limits are consistent with prevailing industry practice at the time. Because the minerals contained in the city water concentrated in the boiler, boiler water was periodically blown down by bleeding the lower header of the boiler to limit the concentration of minerals in the boiler. Blowdown was conducted once per day. The average volume of blowdown per day was approximately 52,000 gallons total for the twenty-four low pressure boilers. (Available data regarding chemical composition of the low pressure boiler blowdown is contained in Table 3.4).

The boiler blowdown was routed to a blowdown pit, an in-ground concrete structure. Available documentation indicates that the construction of the blowdown pit was of a type that facilitated the evaporation of the hot blowdown water. Residual minerals and water were percolated to the ground.

#### **3.1.2.2 Non-Contact Cooling**

Non-contact cooling water used to condense turbine exhaust steam was withdrawn from the Passaic River. The non-contact cooling water was pumped through the condensers and discharged directly back to the river.

The cooling water intake was equipped with twelve circulating water pumps (two per condenser) with an original non-contact cooling water design capacity (as of 1924) of 378,500 gallons per minute ("gpm").<sup>1</sup> The water intake was equipped with a trash rack, traveling screens and a trash sluice which were used to remove and manage debris from the water withdrawn from the Passaic River.

The low pressure boiler plant had six condensers. The condensers were steel or cast iron closed box-like vessels, consisting of an inlet water box, condenser tube bundles (supported by tube sheets) and an outlet waterbox. Tubes were approximately 3/4" in diameter. The flooded capacity of the waterside of the condensers were: two condensers at 7,800 gallons, two condensers at 13,500 gallons, and two condensers at 15,550 gallons. The condensers were mounted under the turbines so that the steam from the turbines exhausted directly into the top of the condensers. Exhaust steam entered the top of the condensers, passed down, around and between the tubes. The outside of the condenser tubes were exposed to steam and the inside to the non-contact cooling water. Condensate formed by the cooling of the steam was collected and routed to a surge tank for re-use in the generation of steam. In condensing this relatively

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<sup>1</sup>The cooling water system was upgraded in 1947. The upgrade resulted in an increase in the non-contact cooling water flow design capacity to 430,500 gpm.

large volume of steam into a smaller volume of water, a vacuum is created on the steamside of the condenser which reduces the back pressure on the turbine and increases the unit's efficiency.

The river water used for non-contact cooling entered the inlet water box and flowed through the condenser tubes in sufficient quantity to condense the turbine exhaust steam. The non-contact cooling water exited the condenser at the outlet water box and was directly discharged to the river through the discharge canal.

Organisms in the river water (e.g., barnacles, algae and river grass) attached themselves and grew on the interior of the inlet and outlet water boxes of the condenser, inside the condenser tubes and on the tube sheets. The growth of these organisms fouled the water boxes and the inner walls of the condenser tubes causing cooling water flow restriction which in turn reduced the cooling efficiency of the condensers.

A chlorination system was installed in 1933 which allowed the automatic injection of chlorine into the non-contact cooling water ahead of the condensers. Chlorine was used as a biocide to control the growth of organisms on the heat exchange surfaces of the condenser. Chlorination of the river water substantially reduced biofouling conditions in the condensers, thereby maintaining the cooling efficiency of the condensers. Chlorine was stored on-site in a pressurized metal storage container, typically a thirty (30) ton railcar.

Information concerning the frequency and/or volume of chlorine injection is limited over

the operating life of the steam units. Available information indicates that when all units were in service, each section of the intake canal would have received the chlorine at the same rate. This information also indicates that the total daily use would have ranged from 1400 to 2000 pounds per day.

In 1974 when the Station filed its application for a National Pollutant Discharge Elimination System ("NPDES") permit, only Unit No. 1 was operating and only one of the three sections of the intake canal was in service. The Station's May 1974 application indicates that the non-contact cooling water was chlorinated twice a day for 135 minutes per period at a rate of 125 lbs per hour for a maximum daily consumption rate of approximately 565 lbs of chlorine per day.

Lubricating oils were used to cool and lubricate rotating equipment, such as the boiler feed pumps and the turbine shaft load-bearing surfaces. The heated lubricating oils needed to be cooled for reuse. River water used for non-contact cooling was pumped through small tubed heat exchangers which cooled the lubricating oils flowing through the oil space of the heat exchangers. Heat exchanger design and operation was similar to that of the condensers.

City water and condensate were also used to cool certain auxiliary equipment in a similar manner in heat exchanger-type equipment which operated in a manner similar to that of the condenser. All cooling water (river water and city water) was directly discharged to the Passaic River via the discharge canal. Condensate, however, was recovered for re-use in the steam

generation process.

### **3.1.2.3 Station Sewer System (Non-Sanitary)**

The Station had a system of sewer piping ("Station Sewer System") which was used to convey process wastewaters to the Passaic River. The Station Sewer System fed directly to the Station non-contact cooling water system. Based on available engineering drawings, the core component of this system may be summarized as follows:

- Two 8 inch and two 24 inch ceramic tile lines from the Boiler House -- these lines ran from south to north and were placed in an alternative sequence starting with an 8" on the west side of the building followed by a 24", an 8" and a 24", all of these lines discharged into the non-contact cooling water discharge canal. Roof drains and floor drains from the Boiler House, coal bunker and the east side of the Turbine Building; sump pump and direct pipe equipment drains were believed to be discharged into these lines. Discharges from these lines other than storm water were ended circa 1978 with the deactivation of the steam generation equipment.
- 18 inch ceramic tile line from the Switch House/Turbine Building - this line ran from south to north between the two buildings and originally crossed through the Intake Structure foundation and discharged into the non-contact cooling water discharge canal. In 1959, this line was cut at a point just west of the Intake

Structure foundation and rerouted directly to the river. Roof drains from the east side of the Switch House and the west side of the Turbine Building, some Turbine Building floor drains and sump pumps were believed to discharge to this line. Discharge from the line was ended in 1986.

- 12 inch ceramic tile line from the Switch House - this line was from south to north along the west side of the building and originally crossed through the Intake Structure foundation and discharged into the non-contact cooling water discharge canal. In 1959, this line was cut at a point just west of the Intake Structure foundation and rerouted directly to the River. Roof drains from the west side of the building and sump pump discharges were believed to be discharged to this line. Discharges from this pipe ended circa 1897 and the discharge point was reactivated as part of the 1995 permit renewal.

#### **3.1.2.4 Equipment Lubrication**

Station moving equipment required lubrication. Lube oil was heated as it flowed past the rotating bearing surface and was then cooled with non-contact river cooling water for reuse. The turbine lube oil system included equipment which would filter and/or separate solid particles (sludge) contained in the lube oil. The lube oil was reused until its lubricating properties were spent (i.e., the viscosity of the oil was diminished). An early Station print (dated 1917) indicates that water and sludge drains from lube oil filters, and drains from a lube oil storage tank were

directed to the discharge canal where it was commingled with non-contact cooling water prior to discharge to the Passaic River. Later information indicates that waste oil generated through change-out of lubricants was collected in waste oil tanks. The waste oil was sold (or given) to a waste oil recycler, and for some period of the Station's history, was burned in the boilers and/or spread on the roads. Circa 1989, the spent lube oil was manifested off-site for dust control.

### **3.1.3 Raw Materials**

Raw materials used in this electric generation process were coal and oil for boiler fuel, city water for makeup to boilers (and some auxiliary equipment cooling), river water for non-contact cooling, water treatment chemicals, air to facilitate combustion and chemicals for equipment cleaning. Table 3.2 presents a list of these raw materials associated with the operation of the low pressure boilers.

Information concerning the type and quantity of fuels used in the generation of electricity at the Station by year from 1915 until 1995 is summarized in Table 3.5. Station-specific information concerning the physical characteristics and chemical composition of fuels used during operation of the low pressure boilers have not been located. Therefore, relevant literature that describes typical physical characteristics and identifies constituents in the fuels has been used to develop the information in this response.

The primary low pressure boiler fuel was bituminous coal coming primarily from mines in

West Virginia and Pennsylvania. Coal was delivered by barge and stored both in the yard and in a coal bunker house. Coal was crushed in a Bradford breaker to a nominal size of two inches or less prior to introduction in the boilers. Tables 3.6 through 3.9 provide a list of the typical properties and constituents of bituminous coal. Only those constituents identified on the Comprehensive Environmental Response Compensation and Liability Act ("CERCLA") hazardous substance list as a hazardous substance are identified.

Fuel oil used in these boilers in later years was No. 6 Fuel Oil. Fuel oil was delivered by barge, stored on site in above-ground tanks and delivered to the boilers by an intra-facility pipeline. No. 6 Fuel Oil is not listed on CERCLA's hazardous substance list as a hazardous substance. Table 3.10 presents a list of the properties of No. 6 Fuel Oil and Table 3.11 identifies constituents in oil that have been listed on the CERCLA hazardous substance list as hazardous substances.

Chemicals were used in the low pressure boilers to maintain proper water chemistry. (See Section 3.1.2.1). The list of these chemicals is presented in Table 3.2. Low concentrations of these treatment chemicals were used to maintain the boiler chemistry within given limits. Typical low pressure boiler water chemistry limits obtained from relevant literature are presented in Table 3.3, which are consistent with prevailing industry practice at the time.

Chemicals were used in the low pressure boiler to clean condenser tubes. The list of these chemicals is presented in Table 3.2. NEP-22 identified in Table 3.2 was used as an

additive to hydrochloric acid to inhibit or reduce the aggressiveness of the acid when used in boiler or condenser cleanings. Station records and/or data from relevant literature concerning the composition of NEP-22 is not available. Oakite (trisodium phosphate) also identified in Table 3.2 was used as a surfactant and an alkalizer in the cleaning process.

Chlorine was used as a biocide to treat the non-contact river cooling water.

#### **3.1.4 Products**

Electric power was the only product generated at this facility. Table 3.5 provides a listing by year from 1915 to 1924 and from 1938 through 1995 of the electric power generated at Essex. Records of the annual production of electricity produced during the years of 1925 through 1937 are unavailable. Annual production for these years has been estimated based on electric power generation in 1923 and 1924, when the first phase of Station construction was completed.

#### **3.1.5 By-Products**

The coal used in the low pressure stoker boilers prior to 1949 was of a coarse size, two inches or less, and was fed into the boilers at the bottom of the furnace. Burning of coal as a fuel in the low pressure boilers resulted in the production of coal bottom ash. The ash produced was gravity fed along the slope of the stokers into a rotating clinker grinder, where the hot ash was

quenched with river water, fragmented, crushed and then gravity fed into an ash hopper. The ash was transported via the hopper to a small hand-pushed rail car which transported the ash and water to an ash pit. The ash pit was wood-lined on four sides. The dock side was reinforced by a concrete retaining wall. The bottom ash material deposited in the pit settled out of the water to the bottom of the pit. The water which accumulated in the ash pit was decanted via a pipe and discharged to the Passaic River. Given that water was used solely for quenching (cooling and fragmentation), it is believed that the volume of water transferred to the ash pit via the hand-pushed rail cars was not substantial.

The settled ash was subsequently removed from the ash pit by a mobile crane and transported off-site for sale or use as fill material. Company records indicate that revenues were derived from the sale of coal ash from 1950 through 1966. While Company documentation for the pre-1950 period has not been located, it is believed that a market for coal ash existed during the pre-1950 period.

Relevant literature indicates that the average ash percentage in West Virginia and Pennsylvania coal was approximately 10% (Table 3.6). This literature also indicates that the underfeed low pressure stoker boilers were capable of capturing 85% of this coal ash as bottom ash. Station-specific information concerning the chemical composition of bottom ash and fly ash have not been located. Compounds identified on the CERCLA hazardous substance list as hazardous substances have been identified in Pennsylvania and West Virginia coal ash, but at trace levels. (See Tables 3.12 - 3.15.)

Station-specific information concerning the chemical composition of the water overflow from the ash pit is not available. Typical trace chemical constituents listed on the CERCLA hazardous substance list as hazardous substances for ash pit overflow water have, however, been located in relevant literature (Tables 3.16 and 3.17). Relevant literature concerning organic substances are not available for sluice water and ash pit water overflow. As indicated above, relevant literature does indicate that bottom ash contains very low and/or non-detectable levels of organic substances (See Table 3.14). Therefore water overflow from the ash pit would contain even lower levels of such substances.

Burning oil as a fuel in the low pressure boilers also resulted in the production of ash. The ash produced was predominantly (98%) fly ash. Neither Station-specific nor relevant literature concerning the chemical composition of the No. 6 Fuel Oil ash have been located. No. 6 Fuel Oil however contains lower levels of ash than coal, usually in the range of 0.01 percent to 0.5 percent (Table 3.10). Accordingly, ash emissions from No. 6 fuel oil would have been significantly less than ash emissions when firing coal in the boilers.

A residual not captured in the steam electric generation process is the flue gas resulting from fuel combustion. This residual is released via the boiler stack to the atmosphere. The composition of the flue gas emitted varies dependent upon the fuel fired, the equipment design and the level of emission control. Station specific data on emission characteristics are not available. The EPRI PISCES Database and other relevant literature provide information on the identity of the trace constituents in the flue gas from boilers fired by either coal, oil or natural gas

which have been identified by EPA under the Clean Air Act Amendments as hazardous air pollutants. This database also presents emission factors for these trace constituents. Attachment I provides the list of these trace constituents and their associated emission factors.

### **3.1.6 Maintenance Processes**

#### **3.1.6.1 Boiler Cleanings**

The generation of steam in the boilers caused minerals originally contained in boiler feedwater and city water makeup to settle out in the boiler. While certain quantities of minerals collected in the boiler, some would form scale deposits on the inner walls of the boiler tubes. The dissolved oxygen remaining in the boiler water would also react with boiler tube material, forming a thin corrosion layer on the inner surface of the boiler tubes. The presence of the corrosion products and mineral scale deposits decreased the heat transfer efficiency of the boiler tubes. Periodic removal of the corrosion products and mineral scale deposits was required to maintain boiler heat transfer efficiency. The tubes were cleaned by a mechanical process which involved the use of small rotating scrapers, referred to as turbines, which were driven through each tube with water pressure. Station records are not available on the frequency of the mechanical cleanings; however, it is believed, based on prevailing industry practice, that this type of cleaning would have been done on average once per year. The tube cleaning residues were collected at the lower header of the boiler, where the residues were directed by water to a floor drain which was connected to the Station Sewer System. The residues were then directed to the

discharge canal, where they were commingled with the non-contact cooling water and discharged to the Passaic River. Station records are also not available on the chemical composition of the boiler scale, but it is believed that the principal constituents in the boiler scale would have included metal oxides of copper and zinc. Small amounts of these oxides would be expected in the discharge that was commingled with the non-contact cooling waters in the discharge canal.

#### **3.1.6.2 Fireside Cleaning**

Boiler maintenance procedures also included the periodic removal of combustion soot deposited on the exterior of the boiler tubes in the furnace. This soot was removed with the use of air and steam lances with the boiler out of service. Force draft fans at low operating speed were used to move the soot from the furnace chamber to the flue duct. The soot was exhausted to the atmosphere. Some of the heavier soot would have settled in the base of the boiler stack which was periodically cleaned. These materials would have been deposited in the ash pit. Station records concerning the chemical composition of the soot are not available. It is believed, however, that the chemical composition would be similar to that of fly ash.

Circa 1933, the Station began the use of No. 6 Fuel Oil in some of its boilers. An ash residue from combustion of the fuel would build up on the exterior of the boiler tubes. Over time, this ash residue would have reduced heat transfer within the boiler. The boiler was periodically taken out of service and the exterior of the boiler tubes was washed with high pressure city water. The water and the combustion ash residue (carbon black) were flushed to

the bottom of the furnace. The residual would either have passed through a floor drain to the Station Sewer System for discharge to the Passaic River via the discharge canal or have been collected and commingled with other ash in the ash pit. The chemical composition of the ash removed in the washwater is believed to be similar to the ash composition of No. 6 Fuel Oil, the composition of which has not been identified.

#### **3.1.6.3 Condenser Chemical Cleanings**

The use of river water for cooling caused biofouling and the deposition of a corrosion scale on the internal condenser tube surfaces. Although injection of chlorine into the river cooling water substantially reduced biofouling, corrosion scale remained an operating problem. During the early years of operation, the internal tube surfaces were cleaned manually by brushes and the inlet and outlet water boxes and tube sheets were manually scraped. The residuals removed during the manual cleanings were primarily organic materials which would have been handled as trash.

Available Station records indicate that the turbine/generator was out of service for approximately 250 hours per year as a result of these cleanings. This cleaning operation required the turbine/generator to be taken out of service because the low pressure turbine/generators were provided with a single condenser per turbine. The flooded capacity of the waterside of the condensers was 7,800 to 15,500 gallons depending on the condenser.

Later, the Station conducted chemical cleaning of the condenser to remove scales and biofouling materials. Station records concerning the frequency and procedures for chemical cleanings prior to 1945 have not been located. Station records have been located, however, with respect to the frequency and method associated with chemical cleanings from 1945 until the Station's steam boilers were taken out of service in the mid to late 1970s. Available information indicates that a total of twenty-four chemical cleanings were performed on the waterside of the low pressure condensers during the operating history of the Station. Table 3.18 presents a list of cleanings and relevant details concerning each of these cleanings.

The methods utilized in each of these cleanings was generally the same. A chemical cleaning solution was prepared in a chemical mix tank consisting of water, hydrochloric acid ("HCl") and NEP-22. NEP-22 was used as an inhibitor to reduce the dissolution rate of the base metals by the hydrochloric acid. Station records indicate that the solution was prepared and maintained at a concentration ranging from 2% to 5% of HCl. After isolating the condenser, the cleaning solution was pumped into the condenser and recirculated in the condenser tubes for one to two hours. Given that the flooded capacity of the water side of the condensers ranged from 7,800 to 15,500 gallons, an equivalent volume of spent cleaning solution may have been drained directly to the discharge canal where it was commingled with the non-contact cooling water. Considering the flow of the non-contact cooling water in the canal, spent solution would have been diluted by approximately 25 to 1 if discharged over a period of one minute. River water was used to flush any residual material in the waterside of the condenser. Station records as to the chemical composition of the discharge have not been located. A search of relevant literature

fails to identify typical chemical composition data. The discharge to the Passaic River would, however, have contained biological materials (e.g., barnacles), certain metals (e.g., copper and zinc), and a dilute HCl solution.

### **3.2 Unit No. 7 High Pressure Turbine/Generator and Nos. 25 and 26 High Pressure Boilers**

This section presents a discussion of the electric generation process and auxiliary processes involved with the generation of electricity using high pressure turbine/generators and boilers. A process flow diagram has been provided as Figure 3.2.

#### **3.2.1 Process Description**

Eight of the low pressure boilers were demolished in 1937 and two high pressure pulverized coal fired boilers (Nos. 25 & 26) and one high pressure non-condensing turbine/generator (Unit No. 7) were installed. Electric power was generated using the same processes used to generate electric power in the low pressure process. A detailed list of operating parameters of this equipment is provided in Table 3.19.

Boilers Nos. 25 and 26 generated steam at a higher pressure (1250 psi) and a higher temperature (950°F). The steam was fed to a new, high pressure turbine/generator which rotated at a rate of 3600 RPM. Exhaust steam at a pressure of 225 psi from the high pressure turbine was piped to the existing low pressure turbine/generators rather than to condensers, as in the low

pressure system design. The volume/mass of low pressure steam exhausted from the new high pressure turbine effectively replaced the volume/mass of low pressure steam for generation previously produced by the eight low pressure boilers removed from service. The steam was exhausted from the low pressure turbines to the low pressure condensers where it formed condensate. The condensate was pumped to a surge tank where it was combined with condensates from the other low pressure boilers for reuse in the generation of steam. A portion of this water was also pumped to a condensate storage tank for use as a makeup water source for the high pressure units.

Boilers Nos. 25 and 26 were more efficient than the low pressure boilers for a number of reasons, which may be summarized as follows:

- **Fuel Preparation:** The coal type used in these boilers was the same as that used in the low pressure boilers, but the preparation process was improved. The coal was pulverized and reduced to a fine powder which was blown into the boilers with air from the forced draft fan duct. By using pulverized coal, more of the surface area of the fuel was exposed to the oxygen in the air during the combustion process. The pulverized coal was blown through the burners and exited the burner tips where it mixed with air from the forced draft fan in the furnace. This resulted in an increase in the rate at which fuel was heated, resulting in an increase in the boiler combustion temperature by several hundred degrees.
- **Boiler Design:** Two changes in boiler design improved boiler heat transfer efficiency.

The boiler tubes were designed with a smaller diameter, thereby providing more heat transfer surface per unit volume of water. In addition, boiler waterside tubes were installed along the walls and floors of the furnace, increasing the volume of water heated per unit of furnace volume.

- Economizers and Superheaters: Boilers Nos. 25 and 26 contained an economizer and a superheater which are heat recovery equipment. Boiler water preheated by feedwater heaters was routed to the economizer for further preheating prior to circulation through the boiler drum and the furnace boiler tubes. Heated water from the boiler tubes was then circulated to a drum where it separated into water and saturated steam phases. The saturated steam was piped to the superheater section of the boilers where the temperature of the steam was raised to 950°F at a pressure of 1250 psi. This section of the boiler utilized waste flue gases (heated combustion gas) as a heat source, which in the lower pressure boiler had been exhausted out the stack. This use of heat recovery equipment resulted in greater boiler thermal efficiency.

- Air Preheaters: Boilers Nos. 25 and 26 were equipped with air preheaters. Air preheaters are sections of metal plates, called baskets, fitted into a circular form which are rotated at a point between the exhaust duct and the air inlet duct. When the baskets were in the exhaust duct, they received heat from the flue gases exhausted from the boiler. This waste heat would raise the temperature of the metal plates in the air heater baskets. As the baskets rotated out of the flue gas area and into the air inlet duct, the heat stored in the

metal plates would have been released (transferred) into the incoming air for use in the combustion process. As was the case with the superheater and economizer, the air heaters utilized as a heat source what had previously been waste flue gases in the low pressure boilers. The use of air heaters to pre-heat the combustion air to the boiler also increased the overall Station thermal efficiency.

- Feedwater Heaters: Boilers Nos. 25 and 26 were equipped with feedwater heaters, which used extracted (bleed) steam from the turbines to pre-heat boiler feedwater. Preheating of the boiler water increased the overall thermal efficiency of the Station by reducing the amount of fuel required to generate a unit value of electricity.
- Electrostatic Precipitators: Boilers Nos. 25 and 26 were equipped with electrostatic precipitators ("ESPs") collected fly ash particles from the exhaust flue gases, thus reducing particulate emissions associated with the generation of fly ash. Collected fly ash from the precipitators was fed to stationary hoppers and then piped to the bottom ash collection pit in the bottom of the boiler.

### **3.2.2 Auxiliary Process**

#### **3.2.2.1 Boiler Water**

Boiler water for operation of the high pressure boilers was supplied by condensate from

the condensate storage tank that was fed from the low pressure boiler system. Condensate from this source had been chemically treated, deaerated and distilled in the low pressure boiler system process. This condensate was gravity fed from the condensate storage tank to the high pressure boilers by way of a feed water deaerator, which preheated the condensate. The deaerator was a more efficient design compared to the low pressure boiler system open heaters.

Sodium sulfite was added to the feed water at the deaerator to remove dissolved oxygen. Trisodium phosphate was also fed to the deaerator to establish and maintain a boiler water pH low enough to prevent caustic embrittlement of boiler tubes. Typical high pressure boiler water chemistry limits employed by the Station are presented in Table 3.21. These limits were consistent with industry practice at the time. The water was gravity fed to the condensate pumps, which pumped the condensate through the low pressure feedwater heater for further preheating. The water was then directed to the boiler feed pumps, then through a high pressure feed water heater before entering the boiler. Minerals in the water (boiler feed) collected in the boiler drum. The quantity of minerals in the high pressure boiler water was considerably less than in the low pressure boiler water because of the use of the pure condensate from the lower pressure boiler system for makeup. This reduced the amount of boiler chemicals required. Blowdown was conducted on a continuous basis at a rate of 10 to 20 gpm. The boiler blowdown was collected and routed to a drain tank, and then to the open heaters for preheating and reuse in the generation of steam in the low pressure boilers.

#### **3.2.2.2 Non-Contact Cooling**

As discussed above, the high pressure turbine/generator (Unit No. 7) that was installed with the two high pressure boilers (Nos. 25 & 26) was a topping, non-condensing turbine. There was no condenser for Unit No. 7 and therefore no non-contact cooling water was required for the system. The steam exhausted from Unit No. 7 was routed to the low pressure turbines to generate electricity. This steam, when exhausted from the low pressure turbines, was then routed to the existing low pressure condensers for condensing. The condensate was then routed to the condensate tank for reuse in the steam generation process.

Lubricating oils were used to cool and lubricate rotating equipment, such as the boiler feed pumps and the turbine shaft load-bearing surfaces. The lubricating oils were in a closed looped system and accordingly, once heated the lubricating oils needed to be cooled for reuse. Non-contact river cooling water was pumped through small tubed heat exchangers where the river water cooled the lubricating oils. Heat exchanger design and operation were similar to that of the condensers.

### **3.2.2.3 Equipment Lubrication**

Station moving equipment required lubrication. Lube oil was heated as it flowed past the rotating bearing surface and was then cooled with non-contact river cooling water for reuse. The turbine lube oil system included equipment which would filter and/or separate solid particles (sludge) contained in the lube oil. The lube oil was reused until its lubricating properties were spent (i.e., the viscosity of the oil was diminished). An early Station print (dated 1917) indicates

that water and sludge drains from lube oil filters, and drains from a lube oil storage tank were directed to the discharge canal where it was commingled with non-contact cooling water prior to discharge to the Passaic River. Later information indicates that waste oil generated through change-out of lubricants was collected in waste oil tanks. The waste oil was sold (or given) to a waste oil recycler, and for some period of the Station's history, was burned in the boilers and/or spread on the roads. Circa 1989, the spent lube oil was manifested off-site for dust control.

### **3.2.3 Raw Materials**

Raw materials used in this electric generation process were coal and oil for boiler fuel, city water for some auxiliary equipment cooling, boiler water treatment chemicals, air to facilitate combustion and chemicals for equipment cleaning. Table 3.20 presents a list of these raw materials.

Information concerning the type and quantity of fuels used in the generation of electricity at the Station by year from 1915 through 1995 is summarized in Table 3.5. Station-specific information concerning the physical characteristics and chemical composition of fuels used during operation of these high pressure boilers has not been located.

The coal used at the Station was bituminous coal coming primarily from mines in West Virginia and Pennsylvania. Coal for these units was delivered to and managed by the Station in the same manner as the coal for the low pressure boilers. Coal was crushed in a Bradford

breaker to a nominal size of two inches or less. After crushing, the coal was delivered to the pulverizers and reduced to a fine powder. This coal powder was then blown in the boilers with air through specially designed burners. Table 3.6 presents the typical chemical composition of these coals and Tables 3.7 through 3.9 list the constituents of these coals that are on the CERCLA hazardous substance list as hazardous substances.

In later years, the fuel oil used in these boilers, was No. 6 Fuel Oil. Fuel oil was delivered by barge, stored on site in above-ground tanks and delivered to the boilers by pipeline. Tables 3.10 and 3.11 present a list of the properties of the oil and constituents of No. 6 Fuel Oil that are on the CERCLA hazardous substance list as hazardous substances.

Chemicals were used in the high pressure boilers to maintain proper boiler water chemistry. The list of these chemicals is presented in Table 3.20. Low concentrations of these treatment chemicals were used to maintain the boiler chemistry within given limits. Typical high pressure boiler water chemistry limits employed by the Station are presented in Table 3.21. These limits were consistent with industry practice at the time.

Chemicals were used to clean boiler tubes and feedwater heaters. A list of these chemicals is presented in Tables 3.22 and 3.23 respectively.

#### **3.2.4 Products**

Electric power was the only product produced at this facility. Table 3.5 provides a listing by year from 1915 to 1924 and from 1938 through 1995 of the electric power generated at Essex. Documentation of the annual production of electricity produced during the years of 1925 through 1937 is unavailable. Annual production for these years has been estimated based on electric power generation and fuel usage in 1923 and 1924 when the first phase of Station construction was completed.

### **3.2.5 By-Products**

The use of pulverized coal changed the type of ash generated from primarily bottom ash or cinders to primarily a fly ash. The fly ash suspended in the combustion gases would move through the boiler to the stack where it would be collected in ESPs. Relevant literature indicates that these ESPs were very efficient (i.e. 90%) in removing fly ash from the flue gas. Fly ash collected by the ESPs dropped into stationary hoppers and was piped to a slag tank pit at the bottom of the boiler, mixed with the bottom ash and sluiced via a concrete lined sluice trench to the ash pit. The bottom ash was collected on the floor of the furnace as a molten slag and flowed over a water-cooled dam into a slag tank pit where it was quenched with river water. The resultant sluice was gravity fed to the sluice trench, and transported to the ash pit.

The ash handling system was modified in 1947, coincident with the construction of New Unit No. 1. The bottom ash was collected on the floor of the furnace as a molten slag, which flowed over a water-cooled dam into a slag tank where it was quenched with river water. The

resultant sludge was pumped to an ash lake, where solids were settled out and the sludge water was decanted to the Passaic River by means of an overflow box and discharge pipe.

The ash produced was generally collected by material handling equipment on the property for sale or other off-site disposition such as for fill. Company records indicate that revenues were derived from the sale of this coal ash from 1950 through 1966. Although documentation for the pre-1950s is not available, it is believed that a market for coal ash existed during the pre-1950 period.

Relevant literature indicates that the average ash percentage in West Virginia and Pennsylvania coal was approximately 10% (Table 3.6). Station-specific information concerning the chemical composition of bottom ash and fly ash is not available. Tables 3.12 through 3.15 identify the constituents in the bottom and fly ashes from these coals which are on the CERCLA hazardous substance list as hazardous substances.

Station-specific information concerning the chemical composition of the water overflow from the ash pit is not available. Tables 3.16 and 3.17 identify the constituents that may have been in the sludge water and overflow from the ash pit which are on the CERCLA hazardous substance list as hazardous substances. Relevant literature concerning organic substances are not available for sludge water and water overflow. As indicated above, relevant literature does indicate that bottom ash contains very low and/or non-detectable levels of organic substances. (See Table 3.14). Therefore, sludge water and water overflow from the ash pit/pond would

contain even lower levels of such substances.

Burning of oil as a fuel also resulted in the production of ash, predominantly fly ash (98%). Station specific information concerning the chemical composition of fuel oil bottom and fly ash is not available. Fuel oil typically contains only 0.01-0.5% by weight ash (Table 3.10).

A residual not captured in the steam electric generation process is the flue gas resulting from fuel combustion. This residual is released via the boiler stack to the atmosphere. The composition of the flue gas emitted varies dependent upon the fuel fired, the equipment design and the level of emission control. Station specific data on emission characteristics are not available. The EPRI PISCES Database and other relevant literature provide information on the identity of the trace constituents in the flue gas from boilers fired by either coal, oil or natural gas which have been identified by EPA under the Clean Air Act Amendments as hazardous air pollutants. This database also presents emission factors for these trace constituents. Attachment I provides the list of these trace constituents and their associated emission factors.

### **3.2.6 Maintenance Processes**

#### **3.2.6.1 Boiler Cleanings**

Periodic removal of corrosion and scale on the interior of the boiler tubes was required to maintain boiler heat transfer efficiency. The tubes in the high pressure boilers were more

numerous and smaller in diameter than in the low pressure boilers, making the cleaning of the tube surfaces using mechanical methods impossible. A cleaning process using chemicals was necessary. Chemical cleaning of the boilers generally involved the cleaning of only the waterside boiler tubes and drums. The maximum flooded capacity of these boiler components was 13,000 gallons. The economizers were generally not chemically cleaned. The superheaters were not cleaned.

Available information indicates that the waterside of each of the two high pressure boilers (Nos. 25 and 26) was chemically cleaned twenty-three times. A chemical solution of HCl and NEP-22 was used in the first twenty-one cleanings. The solution was prepared and maintained at a concentration ranging from 1% to 5% HCl. The twenty-first cleaning of each boiler was done using Vertan 675 (tetra ammonium ethylene diamine tetra acetic acid). The twenty-second cleaning for each boiler was done using Citrosolv, an ammoniated citric acid. Table 3.22 lists the cleanings and presents details associated with each cleaning.

For the cleanings which used inhibited HCl, the boiler tubes were drained. Chemical solutions were mixed with water in a chemical cleaning tank and the resultant solution was pumped into the boiler waterside and circulated through the boiler water tubes. The boiler tubes were filled once, with the chemical cleaning solution, circulated and drained. The solution was recirculated to the chemical cleaning tanks for concentration analysis, additional chemicals were added as required, and then the solution was pumped back to the waterside of the boiler for recirculation through the boiler tubes. After the boiler tubes were drained, the boiler waterside

was flushed with fresh water. Station records documenting the methods used to handle the spent cleaning solution or rinse waters from these cleanings or the chemical composition of the spent solution or rinse waters have not been located. Prevailing industry practice, however, was to direct the spent cleaning solution to the discharge canal where it was commingled with the non-contact cooling water and discharged to the Passaic River. Relevant literature provides typical compositional makeup of the spent solution and the first rinse drain. The compositional data are presented in Table 3.24.

Subsequent cleanings (Nos. 21 and 22) utilized alternate chemical cleaning methods that improved cleaning efficiency, i.e. iron and copper removal. Vertan 675 or CitroSolv was used in these cleanings. The waterside was isolated after introduction of the chemicals. The solution was circulated through the boiler waterside by periodically heating and cooling the solution. The spent cleaning solution was either directed to the other boiler (No. 25 if 26 were being cleaned and No. 26 if 25 were being cleaned) and evaporated in the furnace of the boiler, or trucked off site (see Table 3.22). The boiler waterside was flushed with water after the boiler tubes were drained of solution. Rinse water was drained to the discharge canal where it was commingled with the non-contact cooling water and discharged to the Passaic River.

#### **3.2.6.2 Chemical Cleaning of Feedwater Heaters**

The electric generation process associated with the use of higher pressure boilers (Nos. 25 and 26) utilized feedwater heaters to pre-heat water for steam generation. Feedwater heaters are

heat exchange devices containing tubing similar to condensers. Station records concerning the flooded capacity of the waterside and steamside for Units 25 and 26 feedwater heaters are not available. The capacities, however, would have most likely been similar to the capacities for the New Unit No. 1 feedwater heaters, i.e. flooded capacity of the waterside of 400 gallons and of the steamside of approximately 1,500 gallons (See Section 3.3.6.3).

As was the case for the boiler tubes, the flow of water in the feedwater heater tubes created the potential for deposition of corrosion scale and mineral deposits on the inside of the tubes. This reduced the heat transfer efficiency of the feedwater heaters. Chemical cleanings were performed to remove scale and mineral deposits to increase effectiveness of heat transfer.

Available information indicates that fourteen cleanings were performed. Table 3.23 lists the cleanings and relevant details associated with each of the cleanings.

The method for all of these cleanings was generally the same. A cleaning solution consisting of water, a chemical cleaning agent and an inhibitor was prepared in the chemical mix tank. The cleanings were one volume cleanings. Cyanide and, later, HCl were used as the cleaning agents. The cleaning solution was circulated within the tubes in the feedwater heater. The tubes were likely rinsed with city water. Station records documenting the discharge of the spent cleaning solution and rinses have not been located. Prevailing industry practice, however, was to direct the spent cleaning solution to the discharge canal where it was commingled with the non-contact cooling water and discharged to the river.

### **3.2.6.3 Air Heater Washes**

Air heaters were washed with river water to remove ash, dust, and soot from the air heater baskets to ensure maintenance of heat transfer efficiency. The air heaters were cleaned one to two times each year. The washwater was directed to the ash sluiceway and routed to the ash pit until 1947, when it was routed to the ash lake. Circa 1970, when the ash lake was removed, the wash water was rerouted to the chemical waste basin (See Section 4.1.5).

### **3.2.6.4 Fireside Wash**

When firing No. 6 Fuel Oil, combustion ash residues (e.g., soot) would build up on the exterior of the boiler tubes. Over time, this residue would reduce heat transfer within the boiler. The boiler was periodically taken out of service and the exterior of the boiler tubes was washed with high pressure city water.

The water and combustion ash residues were flushed to the bottom of the furnace. The residual was drained to a floor drain, directed to the discharge canal, commingled with the non-contact cooling water, and discharged to the Passaic River.

## **3.3 High Pressure Unit No. 1**

This section presents a discussion of the electric generation process and auxiliary

processes involved with the generation of electricity using a unitized high pressure boiler and multi-stage turbine/ generator. A process flow diagram is depicted in Figure 3.3. The boiler and turbine/generator are tied together in a unitized system, and are independent from the rest of the generating Station equipment.

### **3.3.1 Process Description**

Circa 1946, four low pressure boilers and one low pressure turbine/generator (original Unit No. 1) were removed from service. One high pressure boiler with one high pressure tandem compound double-flow turbine/generator ("New Unit No. 1") was installed. The boiler supplied steam only to the New Unit No. 1 high pressure turbine. The New Unit No. 1 boiler was designed to burn coal, oil or gas. All three fuels were used interchangeably in this unit depending on a myriad of factors including fuel cost and availability.

Electric power was produced in this unit in a manner similar to that in the other Station electric generation processes described in Sections 3.1 and 3.2. While physically larger, the boiler design included a number of the same component equipment as high pressure boiler Nos. 25 & 26 (i.e., furnace with wall and floor tubes, economizer and superheater sections, feedwater heaters, air pre-heaters, pulverizers, and electrostatic precipitators). The boiler design incorporated a more sophisticated feedwater heating system and boiler tubes that were even smaller in diameter than the tubes in Nos. 25 and 26 boiler. Again, as with the design of Nos. 25 and 26 boilers, the design was focused on the capture for reuse of water and waste energy,

thereby increasing the net Station thermal efficiency.

The boiler generated steam at a pressure of 1265 psi at a temperature of 1000°F. The turbine/generator shaft rotated at a rate of 3600 rpm. Exhaust steam was directed to a dedicated condenser where the steam was condensed to water. The waterside flooded capacity of this condenser was 17,460 gallons. Condensate was collected in a hotwell and gravity fed to condensate pumps. The hotwell operated under a vacuum and served a function similar to that of the deaerator removing oxygen from the condensate. The condensate was pumped through a condensate cooler (containing water-filled tubes) for further cooling using river water as the non-contact coolant. The cooled condensate water was then pumped to generator coolers and other miscellaneous coolers for use as a coolant for auxiliary equipment. This was the first stage for the preheating of the condensate water for reuse as boiler feedwater. The feedwater to the boiler was then routed through a series of feedwater heaters for further preheating prior to being routed to the boiler for steam generation. The heat source for the feedwater heaters was steam, extracted from various stages of the turbine exhaust. This steam was re-routed to the hotwell as a condensate after passing through the feedwater heaters, and subsequently re-circulated through the feedwater heaters and back to the boiler for steam generation.

The unit had an ESP which captured the fly ash. When coal was used as the boiler fuel, fly ash captured by the ESP was returned to the furnace and fired. This significantly reduced the volume of fly ash and improved overall Station thermal efficiency. Fly ash returned to the boiler would increase the quantity of bottom ash.

### **3.3.2 Auxiliary Processes**

#### **3.3.2.1 Boiler Water**

Water used to generate steam in New Unit No. 1 boiler was supplied by condensates from the existing low pressure boilers. The condensate had been chemically treated, deaerated and distilled in the low pressure boilers. This condensate was gravity fed from the condensate storage tank where it had been collected from the low pressure system, and pumped to a hotwell. The hotwell replaced the function performed by the deaerator used in Boilers No. 25 and 26. The water was then routed to the condensate cooler for cooling and then circulated through the condensate and feedwater system for use in the boiler for steam generation. Sodium sulfite solution was pumped into the feed water to the boiler drum to remove any residual oxygen. Trisodium phosphate solution was pumped to the boiler drum to maintain pH between 10.5 and 10.8. Typical boiler chemistry limits are provided in Table 3.27. These limits are consistent with prevailing industry practice at the time. Boiler blowdown was conducted on a continuous basis at a rate of 10 to 20 gpm, piped to a drain tank and routed to the low pressure boiler open heaters. The open heaters fed condensate/blowdown to the existing low pressure boilers for reuse in the generation of steam, as the quality of the high pressure boiler blowdown was better than that of city water. Overflow from the drain tank was routed to the Passaic River.

#### **3.3.2.2 Non-Contact Cooling**

New Unit No. 1 was equipped with one condenser. The non-contact cooling process exhausted steam for New Unit No. 1 was the same process utilized for non-contact cooling of exhausted steam in the low pressure system. In connection with the installation of this unit, the cooling water intake system was upgraded, increasing the non-contact cooling water flow design capacity to 430,500 gpm.

Lubricating oils were used to cool and lubricate rotating equipment, such as the boiler feed pumps and the turbine shaft load-bearing surfaces. The heated lubricating oils needed to be cooled for reuse. River cooling water was pumped through small tubed heat exchangers where the river water cooled the lubricating oils. Heat exchanger design and operation were similar to that of the condensers. The cooled lubricating oils were reused in a closed cycle for equipment lubrication and cooling.

### **3.3.2.3 Equipment Lubrication**

Station moving equipment required lubrication. Lube oil was heated as it flowed past the rotating bearing surface and was then cooled with non-contact river cooling water for reuse. The turbine lube oil system included equipment which would filter and/or separate solid particles (sludge) contained in the lube oil. The lube oil was reused until its lubricating properties were spent (i.e., the viscosity of the oil was diminished). An early Station print (dated 1917) indicates that water and sludge drains from lube oil filters, and drains from a lube oil storage tank were directed to the discharge canal where it was commingled with non-contact cooling water prior to

discharge to the Passaic River. Later information indicates that waste oil generated through change-out of lubricants was collected in waste oil tanks. The waste oil was sold (or given) to a waste oil recycler, and for some period of the Station's history, was burned in the boilers and/or spread on the roads. Circa 1989, the spent lube oil was manifested off-site for dust control.

### **3.3.3 Raw Materials**

Raw materials used in this electric generation process were coal, oil, or gas for boiler fuel, city water for some auxiliary equipment cooling, river water for non-contact cooling, boiler water treatment chemicals, air to facilitate combustion and chemicals for equipment cleaning. Table 3.25 presents a list of these raw materials.

Information concerning the type and quantity of fuels used in the generation of electricity at the Station by year from 1915 through 1995 is summarized in Table 3.5. Station-specific information concerning the physical characteristics and chemical composition of materials used during operation of the high pressure boilers is unavailable.

The coal was bituminous coal primarily from mines in West Virginia and Pennsylvania. Coal was crushed in a Bradford breaker to a nominal size of two inches or less. After crushing, the coal was delivered to the pulverizer and reduced to a fine powder. This coal powder was then blown in the boiler with air through specially designed burners. Table 3.6 presents a list of the chemical properties of these coals and Tables 3.7 through 3.9 identifies those constituents

which are on the CERCLA hazardous substance list as a hazardous substance.

The fuel oil used in New Unit No. 1 boiler was No. 6 Fuel Oil. Tables 3.10 and 3.11 present a list of the properties of the oil and constituents identified in No. 6 Fuel Oil that are on the CERCLA hazardous substance list as a hazardous substance. Fuel oil was delivered by barge, stored on site in above ground storage tanks and delivered to the boilers by pipeline. Natural gas was also used as a boiler fuel New Unit No. 1. Natural gas was fed to the Station via a high pressure transmission line from Transcontinental Gas Pipe Line Corporation. Table 3.26 presents the typical chemical composition of natural gas.

Chemicals were used in the high pressure boilers to maintain proper water quality. The list of these chemicals is presented in Table 3.25. Low concentrations of these treatment chemicals were used to maintain the boiler chemistry within given limits. Typical high pressure boiler water chemistry limits employed by the Station are presented in Table 3.27. These limits were consistent with prevailing industry practice at that time.

Chemicals were used to clean the boiler condensers and feedwater heaters. These chemicals are presented in Table 3.25.

Chlorine was used to treat the non-contact cooling water. Chlorine was stored on-site in pressurized metal storage containers.

### **3.3.4 Products**

Electric power was the only product generated at this facility. Table 3.5 provides a listing by year from 1915 to 1924 and from 1938 through 1995 of the electric power generated at Essex. Station records as to the annual production of electricity during the years of 1925 through 1937 are unavailable. Annual production for these years has been estimated based on electric power generation in 1923 and 1924, when the first phase of Station construction was completed.

### **3.3.5 By-Products**

The use of pulverized coal changed the type of ash generated. Similar to Nos. 25 and 26 boilers, the ash produced was primarily fly ash; the balance was bottom ash. The fly ash would be carried suspended in the combustion gases through the boiler. Fly ash was collected by the electrostatic precipitator and then gravity fed to stationary hoppers and returned to the boiler for refiring. Fly ash was introduced back into the furnace through "dust nozzles" for recombustion, forming additional bottom ash.

The electrostatic precipitators installed at Essex were some of the earliest applications of this technology. Relevant literature indicates that these emission control systems were very efficient in removing fly ash from the boiler exhaust gases generally 90% or greater.

The ash handling system was modified in 1947, coincident with the construction of the New Unit No. 1. The bottom ash was collected on the floor of the furnace as a molten slag and flowed through a slag tap into a slag tank where it was quenched with river water. The resultant ash sludge was then pumped to an ash lake where solids were settled out. Water was decanted to the River by means of an overflow box and discharge pipe.

Relevant literature indicates that the average ash percentage in West Virginia and Pennsylvania coal was 10% (Table 3.6). Station-specific information concerning the chemical composition of bottom ash and fly ash is not available. Tables 3.12 through 3.15 identify the constituents identified for bottom and fly ash from West Virginia and Pennsylvania coals that are on the CERCLA hazardous substance list as hazardous substances.

Station-specific information concerning the chemical composition of the water overflow from the ash lake is not available. Using data available from relevant literature, Tables 3.16 and 3.17 present the constituents that were believed to be present for this water which are on the CERCLA hazardous substance list as hazardous substances. Relevant literature concerning organic substances is not available for sludge water and water overflow. As indicated above, relevant literature does indicate that bottom ash contains very low and/or non-detectable levels of organic substances. (Table 3.14) Therefore, sludge water and water overflow from the ash lake would contain even lower levels of such substances.

The ash produced was generally collected by material handling equipment on the property

for sale or other off-site disposition. Company records indicate that revenues were derived from the sale of this coal ash from 1950 through 1966. Although documentation is not available, it is believed that a market for coal ash existed during the pre-1950 period.

A residual not captured in the steam electric generation process is the flue gas resulting from fuel combustion. This residual is released via the boiler stack to the atmosphere. The composition of the flue gas emitted varies dependent upon the fuel fired, the equipment design and the level of emission control. Station specific data on emission characteristics are not available. The EPRI PISCES Database and other relevant literature provide information on the identity of the trace constituents in the flue gas from boilers fired by either coal, oil or natural gas which have been identified by EPA under the Clean Air Act Amendments as hazardous air pollutants. This database also presents emission factors for these trace constituents. Attachment I provides the list of these trace constituents and their associated emission factors.

### **3.3.6 Maintenance Processes**

#### **3.3.6.1 Boiler Cleanings**

Periodic removal of corrosion and scale on the interior of the boiler tubes was required to maintain boiler heat transfer efficiency. As was the case with high pressure boilers Nos. 25 and 26, the tubes in the high pressure Boiler No. 1 were more numerous and smaller in diameter than in the low pressure boilers, making the cleaning of the tube surfaces using mechanical methods

impossible. A cleaning process using chemicals was necessary. Chemical cleaning of the boilers involved only the cleaning of the waterside boiler tubes, drum and economizer. The flooded capacity of these components was 40,000 gallons. The superheater was not cleaned.

Available information indicates that this high pressure boiler was chemically cleaned once prior to commercial operation (see below) and eight times during its operating history. Table 3.28 presents a list of the cleanings performed during New Unit No. 1 Boiler's operating history and relevant details associated with each of the cleanings. The chemical cleaning done prior to commercial operation used different chemicals and procedures than used to perform the boiler cleanings after commercial operations began.

The pre-operational chemical cleaning was performed on November 15, 1947 utilizing the following procedures: an alkaline boil-out using trisodium phosphate, sodium hydroxide and sodium meta-silicate followed by a rinse; then a conventional acid cleaning using hydrochloric acid (with an inhibitor); and finally three rinses with condensate water. Available documentation indicates that the concentration of HCl in the cleaning solution was 3.8%. The first rinse used city water and condensate from the low pressure system. Available documentation indicates that the concentration of HCl in the first rinse was 0.15%. The second rinse used 0.25% caustic soda and 0.5% trisodium phosphate solution. The third rinse used condensate. Station records documenting the chemical composition of the spent solution or rinse waters have not been located.

The next six cleanings used HCl and were performed during the period from 1949 to 1958. These acid cleanings were performed utilizing methods similar to those used for Boiler Nos. 25 and 26. In addition, the management of the spent cleaning solution and its chemical composition would likely have been the same as that for Boiler Nos. 25 and 26 (See Section 3.2.6.1 and Table 3.24).

An eighth cleaning was performed in October 1965 by an outside contractor - Dow Industrial Services. The cleaning consisted of two stages. The first stage, or "Bromate Stage", was performed for copper oxide removal and utilized a bromate solution consisting of a total of 3,250 gallons of aqua ammonia, 4,900 pounds of ammonium carbonate, and 2,700 pounds of sodium bromate. This solution was placed in the boiler for a six hour soak. Neutralization was performed using 6,000 gallons of 28% HCl. The boiler was then rinsed twice using city water.

The second stage, referred to as the hydrochloric acid stage, used 9,850 gallons of 28% hydrochloric acid (diluted to approximately 7.5%), 120 gallons of A-120 inhibitor, and 10,100 pounds of thiourea (for copper removal -- copper sources being condenser tubes, feedwater heater tubes, etc.). The solution was placed in the boiler for a six hour soak.

Four rinses were performed. The first rinse used condensate. The following three rinses used condensate with 0.50% citric acid, and 100 ppm hydrazine. This was followed by a neutralizing boil out with 0.5% tri-sodium phosphate, 100 ppm hydrazine, and 40,000 gallons of condensate.

Boiler cleaning solutions for this cleaning were collected and routed to an ash sump where river water was added. This solution was pumped from the ash sump to the ash lake. En route a neutralization chemical, caustic soda was added to the solution. The solids settled out and were mixed with the ash in the ash lake. Water was decanted from the ash lake via an overflow pipe and discharged to the Passaic River.

The ninth and last, chemical cleaning of New Unit No. 1 boiler was performed in December 1973. This cleaning was performed by an outside contractor, Dow Industrial Services. The cleaning solution consisted of 6% hydrochloric acid, 2% thiourea, and 0.30% inhibitor. This solution was introduced into the boiler tubes and the furnace temperature was maintained at 140°F to 150°F for a period of approximately 6.5 hours. The first rinse was performed with condensate. The second rinse was performed using 0.10% citric acid. The third rinse used 0.5% caustic which was left to soak in the boiler while the furnace temperature was maintained at 180°F to 190°F. The spent solution was then drained from the boiler, collected in tanker trucks and transported off-site for disposal. The rinse water was believed to have been routed to the chemical waste basin. The cleaning solution and first two rinses were drained under nitrogen to protect the newly-cleaned surfaces.

Station records are not available concerning the chemical composition of the spent solutions and rinse waters. A search of relevant literature has not identified typical compositions for these streams.

### 3.3.6.2 Condenser Chemical Cleanings

The use of river water for cooling caused biofouling and deposition of a corrosive scale on the condenser tube internal surfaces. While injection of chlorine into the river cooling water substantially reduced biofouling, corrosion of condenser tubes remained an operating problem. Station records indicate that the Station conducted condenser chemical cleanings to maintain the thermal efficiency of the condensers.

Station records have been located describing the frequency and method associated with chemical cleanings of New Unit No. 1 condenser. Nine chemical cleanings were performed between 1953 and 1973. Table 3.29 presents a list of these cleanings and relevant information with respect to each of the cleanings.

The methods used in each of these cleanings were generally the same. A chemical cleaning solution was prepared in a chemical mix tank consisting of water, HCl and an inhibitor. The solution was monitored to maintain a concentration of from 2% to 5% HCl. After isolating the condenser, the condenser was pumped full of cleaning solution. The water flooded capacity of the New Unit No. 1 condenser was 17,460 gallons. The solution was then recirculated in the condenser for one to two hours. The solution was drained to the Station Sewer System and to the discharge canal where it was commingled with the non-contact cooling water and discharged to the Passaic River. Given that the flooded capacity of the waterside of the condensers was 17,460 gallons, an equivalent volume of spent solution was drained directly to the discharge

canal where it was commingled with the non-contact cooling water. Considering the flow of the non-contact cooling water in the canal, the spent solution would have been diluted by approximately 25 to 1, if discharge over a period of one minute.

### **3.3.6.3 Chemical Cleaning of Feedwater Heaters**

The electric generation process associated with the use of the New Unit No. 1 boiler utilized feedwater heaters to preheat water for steam generation. Feedwater heaters are heat exchange devices containing tubing similar to those in condensers. The flooded capacity of the waterside of the feedwater heater tubes was 400 gallons and the flooded capacity of the steamside of the heaters was less than 1,500 gallons. As was the case with boilers Nos. 25 and 26, the flow of water in the feedwater heater tubes created the potential for deposition of metal oxide corrosion layers on the inside of the feedwater heater tubes. This deposition reduced heat transfer efficiency. Chemical cleanings were performed to remove the deposition and restore heat transfer efficiency. These cleanings involved both the steamside and waterside; however, they were generally done separately. Station records indicate that cleanings were performed on four separate dates over the operating life of this unit. Table 3.30 lists these cleanings and the details associated with each of the four documented cleanings events.

The method for these cleanings was generally the same. A solution consisting of water, cleaning agent chemicals and an inhibitor was prepared in the chemical mix tank. HCl was generally used as the cleaning agent. The cleaning solution was circulated within the feedwater

heater tubes. The cleaning solution was drained from feedwater heaters to a floor drain to the Station's sewer system routed to the discharge canal, commingled with the non-contact cooling water and discharged to the Passaic River. The tubes were likely rinsed with city water. The rinse was likely discharged in a manner similar to the cleaning solution. Station records and relevant literature documenting the chemical composition of the spent solution or rinse waters have not been located.

#### **3.3.6.4 Air Heater Washes**

Air heaters were washed with river water to remove ash, dust, and soot from the air heater baskets to maintain heat transfer efficiency. The air heaters were cleaned one to two times each year. The washwater was directed to the ash sluiceway and routed to the ash pit until 1947 when it was routed to the ash lake. Circa, 1970 when the ash lake was removed, air heater washes were rerouted to the chemical waste basin as described in Section 4.1.5.

### **3.4 Combustion Gas Turbines (1963 - Present)**

This section presents a discussion of the electric generation process involved with the generation of electricity using combustion turbines. A process flow diagram is provided as Figure 3.4. Table 3.31 provides the operating parameters for the combustion turbine units.

#### **3.4.1 Process Description**

Commencing in 1963, combustion turbine units were installed at the Station. The first unit (Unit No. 8) was installed in 1963 and burned only natural gas. Four additional units were installed, three (Units No. 9 - 11) in 1971 and one (Unit No. 12) in 1972. These units are capable of burning both gas and low sulfur distillate oil as a fuel. As of 1972, the capacity of the combustion turbine units was 585,333 kW (generator nameplate rating). In 1989, Unit No. 9 was destroyed by a fire and retired. In 1990, a new combustion turbine ("New Unit No. 9") was installed. The New Unit No. 9 is capable of burning either low sulfur distillate oil or natural gas. These generating units supply electricity during peak load periods, typically the warmest days in the summer and the coldest days in the winter.

The combustion turbines are pre-fabricated, self-contained electric generating units which combust fuel producing exhaust gases, that drive turbine/generators to produce electricity. Specifically, the combustion turbine units operate as follows: the engine continuously draws filtered air from an inlet plenum, compresses it and mixes it with fuel in the combustion chamber. The fuel is combusted producing hot gases, which are directed to a free turbine. The flow of hot gases exhausts through the turbine and rotates a drive shaft at 3,600 rpm which is coupled to the generator rotor. The generator rotor rotates inside a stator, consisting of a series of copper windings, which produces an electromagnetic field resulting in the generation of electric power. The hot gases are exhausted through the turbine to the atmosphere.

Tables 3.26 and 3.32 and 3.33 present the typical chemical compositions of natural gas,

low sulfur distillate fuel oil and kerosene used as fuel in combustion turbines.<sup>2</sup> Tables 3.34 and 3.35 identify constituents in low sulfur distillate fuel oil and kerosene that have been identified on the CERCLA hazardous substance list as hazardous substances. Raw materials used in the operation of combustion turbine generators are identified in Table 3.36.

There is no solid waste or wastewater effluent stream generated during the combustion turbine generation process other than the discharge of non-contact cooling water that is used in Unit No. 8 to cool lubricating oils (see Section 3.4.2.3).

Unit Nos. 10, 11 and 12 use a smoke suppressant to control the visible emissions (opacity) associated with exhaust gases. Former Unit No. 9 also used a smoke suppressant. The suppressant is (was) continuously injected into the fuel at a rate of one gallon to 2,000 to 2,500 gallons of fuel prior to the combustion chamber. The suppressants that have been used include initially a barium and manganese based formula and later a cerium based formula.

The design of the New Unit No. 9 incorporates a water injection system as part of the combustion process. Demineralized water is injected into the combustion chamber to reduce the emissions of nitrogen oxides ("NO<sub>x</sub>") in gases exhausted to the atmosphere. The water is consumed in the combustion process. The demineralized water is supplied by a contractor and

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<sup>2</sup>PSE&G notes that while the data in these tables are typical for the types of fuels burned in these types of units, PSE&G's combustion turbines burn fuels which comply with New Jersey's more stringent sulfur content regulations (set forth at N.J.A.C. 7:27-9) as well as the more stringent limit imposed in New Unit No. 9's Air Permit.

stored on site for use in the unit.

A residual not captured in the combustion turbine electric generation process is the flue gas resulting from fuel combustion. This residual is released via the exhaust stack to the atmosphere. The composition of the flue gas emitted varies dependent upon the fuel fired, the equipment design and the level of emission control. Station specific data on emission characteristics are limited. The EPRI PISCES Database and other relevant literature provide information on the identity of the trace constituents in the flue gas from boilers fired by either coal, oil or natural gas which have been identified by EPA under the Clean Air Act Amendments as hazardous air pollutants. This database also presents emission factors for these trace constituents. While EPRI has not completed work on the combustion turbine portion of this database, Attachment I provides the list of these trace constituents and their associated emission factors.

### **3.4.2 Ancillary Operations**

#### **3.4.2.1 Engine Cleanings**

Combustion of fuel over time causes carbon deposits to build up in the engine's combustion chamber, reducing combustion efficiency of the unit. The combustion chambers are periodically cleaned to remove these carbon deposits. Three different methods have been used to perform these cleanings.

The first method involved the introduction of pulverized walnut (or pecan) shells into the combustion chamber with the engine running at idle speed. The walnut shells acted as a blasting agent to grind carbon deposits from the metal surfaces. The shells and the carbon deposits were then combusted and exhaust gases discharged through the unit's stack. (It is believed that the characteristics of the exhaust gases during these cleanings may have been similar to the exhaust gases during normal operation).

The second method involved the injection of untreated city water into the combustion chamber with the engine running at idle speed. The water was vaporized and the vapor exhausted to the atmosphere. The carbon deposits were combusted in the combustion chamber and exhaust gases discharged through the stack.

The third method involved the washing of the combustion manifold with the unit off-line with a solution of water and a cleaning surfactant. This technique has been and continues to be conducted once a year when the fuel source is switched from natural gas to oil. One frequently used surfactant is Penetone 19. The Material Safety Data Sheet for this product is available for inspection. The cleaning solution was initially discharged to the Station Sanitary Sewer which discharged to the Passaic Valley Sewerage Commission ("PVSC"). The solution is now collected in drums and disposed off-site by a contractor.

#### **3.4.2.2 Purge Oil Collection System**

The combustion turbines have an automatic purge system which allows unburned distillate oil to drain automatically to underground collection tanks upon unit shut down. The original collection tanks were periodically pumped and the oil was returned to above ground storage tanks for reuse as fuel in the combustion turbine.

Circa 1990, the auxiliary equipment associated with the purge system was upgraded to mitigate the potential for discharges occasioned by a purge valve malfunction. The upgrade included the removal of underground collection tanks and their replacement with new collection tanks inside concrete vaults which act as secondary containment. The purge oil gravity drains into these collection tanks and is automatically pumped via pipeline to an above ground fuel oil storage tank for reuse.

#### **3.4.2.3 Equipment Coolers**

Rotating equipment (e.g., rotors and drive shafts) within the combustion turbines must be lubricated with lube oil at bearing surfaces to minimize friction. The combustion turbines have lube oil reservoirs with capacities ranging up to 3,300 gallons (see Table 3.37). The lube oil is circulated to the bearing where it becomes heated in the process and requires cooling prior to reuse in the system. The lube oil was generally changed during routine maintenance. Table 3.38 identifies constituents in typical lube oil that are listed on the CERCLA hazardous substance list as a hazardous substance.

Lube oil is cooled by passing it through an air-cooled radiator. The lube oil in former Unit No. 8 (dismantled in 1980) was cooled by tubed heat exchangers using city water. The non-contact cooling cycle was a closed looped system. Unless operating conditions required otherwise, the cooling water would have been drained twice annually -- once in the summer to remove the anti-freeze and once in the winter to add anti-freeze. Anti-freeze was added to prevent freezing of the cooling water. Cooling water drained from the system was discharged to a sump pit that also collected storm water. The waters collected in the sump pit were routed to a catch basin and discharged to the Passaic River via Lawyers Ditch. A corrosion inhibitor was added to the cooling water to protect the tubing. Station records do not contain any information on the inhibitor that was used.

#### **3.4.2.4 Stormwater Discharges**

The design of the combustion turbines allowed stormwater to collect in the unit's equipment compartment. This stormwater would enter the unit through exhaust stacks. The stormwater would eventually drain to the floor of the equipment compartment. The stormwater in former Unit No. 8 would collect and be directed to a sump and was pumped via a catch basin to Lawyers Ditch. Stormwater from old Unit No. 9 and Unit Nos. 10, 11 and 12 would pass through the compartment and drain to the ground.

Lube oil or fuel oil drips and leaks on the equipment compartment floor may have mixed with the stormwater prior to discharge. Circa 1990, systems were installed on Units 10, 11 and

12 and incorporated in New Unit No. 9's design to collect storm water that collects in the combustion turbine units. These systems include piping which gravity feeds the water collected on the equipment compartment floor to a collection tank in a concrete vault. This water is then pumped to a double-walled, above ground storage tank. Periodically this water is either disposed of off-site at an approved facility.

### **3.5 House Heating Boiler**

A York Shipley fire tube boiler was installed in 1979 for house heating. The boiler was physically small, approximately 10 feet long and 6 feet in diameter, and burned No. 2 Fuel Oil. This boiler supplied steam for house heating and hot water during the heating season. Hot water during the non-heating season was supplied by means of electric heaters. Auxiliary equipment included a fuel oil storage tank and condensate collection system. The boiler was removed from service in 1994.

Feed water for this boiler was city water, treated with trisodium phosphate. This boiler was a closed loop system. Until the chemical waste basin was removed from service circa 1984, boiler blowdown was routed to the basin where it was allowed to evaporate. After the chemical waste basin was removed from service, the blowdown was collected in a flash tank in the Switch House basement and pumped to the sewage pit, where it was discharged to the PVSC system. Station records concerning the frequency and the volume of blowdown are not available. Available information, however, suggests that the boiler was only blown down when a high level

alarm was activated. The volume of blowdown was de minimis.

### **3.6 Yard Operations**

This section describes the yard operations which were performed in support of electric production. These operations were common to all units and included fuel handling and storage, dock-side operations (e.g., dredging), and ash handling.

#### **3.6.1 Coal Handling and Storage**

Coal was the primary source of fuel for steam operations at Essex from 1915, when the first boilers were installed, until the late 1930s. Commencing circa 1953, fuel oil and later natural gas became the primary boiler fuel(s). The Station ceased using coal as a fuel in 1970.

Coal was delivered to the Station by barge and rail car. Coal was unloaded from the barges using the two coal tower clamshell buckets and placed on conveyors. Coal was unloaded from rail cars by means of a track hopper and placed on conveyors. The conveyors transported the coal to a Bradford Breaker where the coal was broken to a maximum size of two inches. Upon exiting the Bradford Breaker, the coal was directed via conveyor to coal bunkers for inside storage or to the yard for outside storage. Coal directed to the coal bunkers was fed by gravity from the bunkers into a Lorry Crane, which was a traveling hopper. The Lorry Crane dispensed coal into each stoker. Coal directed for outside storage was staged as reserve. Coal was

conveyed to the boilers from outside staging areas, through a "grizzly" (metal grid) for removal of oversized materials and then to the coal bunkers. From the coal bunkers, the coal followed the same path into the stokers as described above.

Pulverizers were introduced into the system with the installation of high pressure boilers Nos. 25 and 26 in 1938. Coal was removed from the barges using a coal tower clamshell bucket and placed on conveyors leading to the Bradford Breaker. Coal exiting the Bradford Breaker was directed to the new coal bunker for Nos. 25 and 26 boilers, the remaining coal bunkers for the stoker boilers, or to the yard for outside storage. By 1941, on-site storage capacity for coal was approximately 134,000 tons. The outside coal storage area was not surrounded by a containment system. Coal exited the coal bunker for Nos. 25 and 26 boilers via Redler conveyors and transported to the pulverizer hoppers. Coal was then gravity fed into the pulverizers, where it was pulverized to the consistency of talcum powder and injected into the boilers through the burners under pressure, using air. Coal from the yard was conveyed via a grizzly to the coal bunkers and then to the pulverizers prior to introduction into the boilers.

Available information indicates that Station personnel reclaimed coal which entered the river during coal barge unloading operations. A clamshell on a railroad steam crane was used. The clamshell was capable of reaching approximately 25 feet out from the dock for a distance of approximately 100 to 125 feet along the dock. The reclaimed coal was used as fuel at the Station.

A supply of Coal Trol was discovered at the Station during demolition. Product packaging indicated that its use was to protect coal stored in outdoor areas from freezing. Station records do not indicate whether it was used, and if so, for what period of time.

### **3.6.2 No. 6 Fuel Oil Handling and Storage**

The Station began to use No. 6 Fuel Oil circa 1933. Fuel oil was brought to the Station primarily by barge. It was unloaded at a barge unloading station at the dock and pumped via pipeline using barge pumps to the Station's fuel oil storage tanks. Circa 1942, Essex installed equipment to allow fuel oil delivery by railcar. Fuel oil was also delivered by truck. In 1973, an Amerada Hess Corporation underground fuel oil pipeline, originating at Hess' Bayonne terminal, was installed and placed into service. This pipeline was the primary source of No. 6 Fuel Oil for the Station through 1978.

A 20,000 barrel steel fuel oil storage tank (Fuel Oil Tank No. 1) was installed circa 1933 on a bed of sand inside a ringwall foundation which was supported by an 18" thick concrete mat. The ringwall partially served as a containment system. The tank was also surrounded by an approximately ten foot high earthen dike. The tank was equipped with a tank oil heater with 1,000 square feet ("sf") of heating surface. This tank was dismantled in 1990.

A 100,000 barrel fuel oil storage tank (Fuel Oil Tank No. 2), which was equipped with two suction heaters, was installed in 1951. It was installed on a bed of sand inside a ringwall

foundation which was supported by a 12" thick concrete mat. The ringwall partially served as a containment system. The tank was also surrounded by an approximately twenty-five foot high steel wall on a concrete foundation. This tank is now used to store demineralized water for New Unit No. 9's water injection system.

### **3.6.3 Natural Gas Supply**

The New Unit No. 1, which was installed in 1947, was designed to burn natural gas, in addition to coal and No. 6 Fuel Oil. Natural gas became available to the Station in 1951 when a Transcontinental Gas Pipeline Corporation natural gas supply pipeline was tied into a PSE&G natural gas line installed at the Station. Natural gas use at the Station increased with the installation of combustion turbines beginning in 1963. All combustion turbine units possessed the capability to burn natural gas. The Station's natural gas supply capacity was increased in 1986 by a tie-in with the Texas Eastern Gas Pipeline ("TETCO") natural gas pipeline at an off-site location.

All Station units which utilized natural gas as a fuel were equipped with scrubbers which collected moisture and other residuals in the natural gas including polychlorinated biphenyls ("PCBs"). Circa 1987, the scrubbers were collecting condensates with PCB contamination. These condensates were collected and drained to 55-gallon drums for storage and eventual off-site disposal.

### **3.6.4 No. 2 Fuel Oil and Kerosene Storage**

No. 2 Fuel Oil and kerosene were used as fuels for combustion turbine Unit Nos. 9, 10, 11 and 12. These fuels were brought to the Station initially by barge. Subsequent to removal of the steam Station from service, No. 2 Fuel Oil and kerosene were brought to the Station by truck.

The fuels were stored in Fuel Oil Tank No. 3 which was installed in 1971. Fuel Oil Tank No. 3 has a capacity of 120,000 barrels and was constructed on a four inch sand bed underlain by a three foot thick concrete slab on wood piles at grade. The tank was surrounded by an earthen dike approximately ten foot high. A claymax liner was installed in 1989 inside the earthen dike containment to provide complete secondary containment for the tank. In 1990, this tank was upgraded by repairing the old floor, which involved installing a new floor with an underlay of an 80 mil polyethylene liner six inches above the old floor.

An 8,000 gallon above ground storage tank was installed in 1979 on a concrete pad for storage of No. 2 Fuel Oil for the house heating boiler. A concrete containment system was constructed in 1986 on a concrete foundation. Fuel was piped via an above ground pipe to the house heating boiler. This tank was removed from service in 1994.

### **3.6.5 Diesel Fuel and Gasoline Storage and Use**

Diesel fuel and gasoline underground storage tanks were installed at the Station. A 1,000

gallon gasoline storage tank was installed in 1924 and a 1,000 gallon steel diesel fuel tank was believed to have been installed circa 1930. A 3,000 gallon steel diesel fuel tank was installed in 1952. A 1,000 gallon fiberglass gasoline tank had also been installed. Date of installation unknown. Station records documenting the removal of the 1924 tank have not been located. These remaining tanks were removed in 1988. Since 1988, fuel for vehicles has been supplied from an above ground tank and/or an off-site source. (See Section 4.5 and Table 3-39).

### **3.6.6 Ash Handling and Removal**

Until 1947, as previously discussed, ash generated in the stoker boilers and Unit Nos. 25 and 26 boilers was deposited in the hoppers and transported to an ash pit, a 20 ft. deep wood-lined excavation with a reinforced concrete wall on the dock side. The ash pit was a settling basin with an overflow line to the Passaic River. The ash settled out and was removed by crane. The decanted water was discharged to the Passaic River.

The Station's ash handling systems were modified in 1947 with the construction of New No. 1 Unit. The new system included an ash sluice system and ash lakes. Ash generated after 1947 was quenched with river water and sluiced out to ash lakes. Dust which collected in the precipitator for New Unit No. 1 was sluiced to the ash lake if it could not be re-fired in the furnace. The ash lakes were man-made above ground structures constructed of earthen diked walls approximately nine feet high. The ash lakes had an overflow piping system for discharging ash lake overflow directly to the Passaic River. Like the ash pit, the ash lake functioned as a

settling basin.

The ash produced was generally collected by material handling equipment on the property for sale or other off-site disposition. Company records indicate that revenues were derived from the sale of this coal ash from 1950 through 1966. Although documentation for the pre-1950s is not available, it is believed that a market for coal ash existed during the pre-1950 period.

### **3.6.7 Refuse**

Refuse generated at the Station was burned on site in a small incinerator unit during the period from 1915 to approximately 1950. The incinerator was a brick pit with a grate. The refuse was deposited in the pit and burned. Incinerator operations ceased circa 1950. Incinerator ash from the incinerator was removed using a crane bucket and placed in the adjacent ash pit. Circa 1950, the Station commenced using trash haulers for refuse disposal.

### **3.6.8 Sewage**

From 1917 through 1927, sanitary sewage consisting of wastes from cafeteria, bathrooms and showers was collected and transported via pipeline to a cistern. No information is available with respect to the specific character of the wastes and whether, and, if so, what treatment of the wastes was performed there. Available information indicates that the cistern discharged to the Passaic River.

The cistern was abandoned in 1927. Sewage ejectors, receiving pits, sewage pumps and piping were installed and the Station's sanitary sewer piping system was connected to the PVSC system. Thereafter, all sanitary sewage from the Station was routed to the PVSC. Circa 1970, wastewater from the Station's laundry was also routed to the PVSC.

### **3.6.9 Dredging Operations**

Dredging operations were routinely performed within the Passaic River adjacent to the Station by the Army Corps of Engineers ("ACOE") and PSE&G.

The ACOE dredged the lower Passaic River to maintain the navigational channel. PSE&G dredged the area in front of the inlet channel to maintain adequate flow of non-contact cooling water and insure adequate depth for barge ingress and egress to and from the dock fuel unloading area.

Table 3.40 contains available information concerning ACOE dredgings encompassing the period from 1917 through 1983.

Available Station records document PSE&G dredging from 1922 through 1975. These records may be summarized as follows:

July 1922      No recorded information is available to estimate quantities. (No information on

disposal.)

May 1924	Approximately 10,972 cubic yards ("cu. yd.") of material were dredged. (Material was to have been disposed "according to law".)
May 1926	No recorded information is available to estimate quantities. (No information on disposal.)
Jan. 1928	12,300 cu. yd. of material dredged. (Material was to have been disposed "in accordance with law".)
Jan. 1929	10,019 cu. yd. of material dredged. (No information on disposal.)
Feb. 1932	15,055 cu. yd. of material dredged. (Material was to have been disposed "in accordance with law".)
May 1941	3,500 cu. yd. of material dredged. (Material disposed at sea)
July 1943	2,500 cu. yd. of material dredged. (No information on disposal)
Jan. 1946	8,000 cu. yd. of material dredged. (No information on disposal)
Dec. 1946	5,481 cu. yd. of material dredged. (No information on disposal)
April 1948	19,620 cu. yd. of material dredged. (Disposal of materials is uncertain)
Feb. 1956	7,680 cu. yd. of material dredged. (Material disposed at sea)
April 1967	27,000 cu. yd. of material dredged. (No information on disposal)
Feb 1975	81,781 cu. yd. of material dredged (Material disposed at sea)

Available Station records concerning PSE&G dredgings are available for inspection.

### **3.7 Demolition Activities**

PSE&G retained Interstate Wrecking Company, Inc. to decommission and demolish the

Station steam Station. Malcolm Pirnie was retained to ensure that materials resulting from the demolition were handled and disposed in compliance with applicable regulatory requirements. The Essex steam Station consisted of four main structures: the turbine building area, the boiler house, the coal bunker, and the switch house. The structural demolition began in June 1990 and was completed in August 1992. The turbine building, boiler house and coal bunker were demolished. The cooling water intakes were sealed. The switch house was not demolished. The demolition consisted of the removal of all asbestos-containing material, mechanical equipment, electrical equipment, and structures. All structural metal removed during the demolition was salvaged by Interstate Wrecking. A total of 3,800 tons of scrap metal went to Naparano Scrap Metal and 10,702 tons of scrap metal went to Trenton Iron. Materials handling activities were generally documented. Relevant documents related to the demolition and related activities are available for inspection.

### **3.8 Substation and Switchyard Operations**

Electrical power from generating stations is directed to switch yard and substation facilities ("Electrical Switching Facility" or "Facility"). Electric Switching Facilities have electric switching equipment which facilitate delivery of the generated electric power to customers at the desired voltage level over a system of wires ("Electrical Conductors"). The Electric Switching Facility and Electric Conductors system is collectively referred to as the utilities' transmission and distribution system. The Electric Switching Facility contains the above-ground equipment necessary to ensure reliable, safe and efficient control necessary for the delivery of electric power

to customers. This equipment includes buses, transformers, breakers, disconnect switches, reactors, and certain low voltage control devices such as relays, potential transformers and current transformers. This equipment may be described as follows:

- Transformers convert electric energy from one voltage level to another to facilitate efficient transportation of power from one location to another and eventually for customer use. The transformers are oil-filled equipment. The oil provides a medium to dissipate heat generated within the transformer's core as a result of electric current flow and also acts as a dielectric insulator to isolate the transformer's internal components.
- Circuit breakers provide a mechanism to interrupt the current between electrical devices for system protection and maintenance. Breakers operate automatically on information from a relay or can be operated manually. Most breakers are oil-filled. The oil serves to extinguish electrical arcing formed by the separating contacts under load.
- Disconnects are manual switches to separate electrical components where and as necessary. Typically, disconnects are not oil-filled and are not designed to be operated automatically. Disconnects are used to provide the required electrical separation necessary to perform regular maintenance operations safely.
- Busses are interconnected copper tubes, supported by ceramic insulators mounted on rigid steel structures, which route electric power to and through equipment in the Electrical Switching Facility. Buses operate in the open air. No further insulation or cooling is required.
- Reactors provide a buffer between two electrical components to protect against surges of

current. Reactors can be oil-filled to provide a means of cooling the internal components. Most are not designed to contain oil.

- Relays, potential transformers and current transformers work as a system to provide protection for Electrical Switching Facility equipment in the event of a system failure. Potential transformers and current transformers are generally oil-filled.

Electrical power is distributed from the Electrical Switching Facility to electric conductors either by overhead wires or underground cables. Underground cables are utilized for transmission with high voltage transmission systems. These cables are generally encased in steel pipe for protection. They contain oil to act as a coolant and a dielectric insulator.

The oil contained in Electrical Switching Facility equipment and underground cables is referred to as transil oil, a dielectric mineral oil. The characteristics of transil oil are described in Tables 3.41 and 3.42.

When the Station commenced commercial operation circa 1915, it housed both indoor and outdoor Electrical Switching Facility equipment. The Electrical Switching Facility was expanded and upgraded in 1925 to tie the Station into PSE&G's high voltage transmission system. This connection enabled PSE&G to have a greater flexibility in the management of peak power demands. This expansion and upgrade included a system to maintain the quality of the oil used in the Electrical Switching Facility Equipment. This system which included above-ground piping, pumps, and a purification facility (containing filter press equipment) provided the Electrical

Switching Facility with the capability to route the oil in the equipment for purification and dehydration and subsequent reuse in connection with routing equipment maintenance. Oil impurities were entrained in the filters and disposed with the filters as a waste. Station records have not been located concerning disposal of these wastes. This system was upgraded circa 1940. It is believed that this system was removed from service circa 1970. Station-specific information has not been located concerning the actual date when the system was removed from service.

In 1936, a fire destroyed a major portion of the Electrical Switching Facility. Over the ensuing four-year period, the facility was rebuilt and expanded to accommodate the Station's upgraded generation capacity and the growth in the surrounding service territory. The Electrical Switching Facility was expanded again in 1953 (to facilitate the tie-in of additional distribution locations) and in the early 1970s (to allow the facility to receive high voltage transmission from outside the Station). An underground oil static cable was also installed in 1953 in place of a bus due to lack of required overhead clearance. Additional underground oil static cables were installed as part of an upgrade of PSE&G's high voltage transmission system.

Table 3.37 presents an inventory of the Electrical Switching Facility equipment that contains transil oil as of circa 1980.

PSE&G conducted a test of the oils in transformers at Electrical Switching Facilities in 1986 to check for the presence and/or levels of PCBs. The data did not disclose the presence of

PCBs in excess of 50 ppm in any Station transformer. PSE&G conducted a second test of oils in transformers at Essex in 1995 which confirmed the results of the initial test.

Tests performed on OCBs, potential transformers and current transformers from New Unit No. 1 in connection with the demolition indicate the presence of elevated levels of PCBs in the transil oil. In addition, these tests indicated elevated levels in the oil purification equipment and three 4,440 lighting transformers.

Tests performed on oil from reactors in 1994 and 1995 indicated that certain units contained elevated levels of PCBs. Records relating to laboratory analyses for the tests described in this section are available for inspection.

#### **4.0 Regulatory Programs**

This section presents a summary of relevant available information concerning certain PSE&G regulatory programs/activities and/or contacts with environmental regulatory agencies related thereto. Correspondence by and between PSE&G and environmental regulatory agencies concerning regulatory programs/activities are available for inspection.

##### **4.1 Effluent Discharges**

The Station supplemented steam electric generation capacity circa 1947 with the

installation of New Unit No. 1 high pressure boiler and tandem compound double-flow turbine/generator, reaching its largest steam electric generating capacity.

The Station's management of non-contact cooling and wastewater effluents changed in 1947. New equipment and facilities for the management of bottom and fly ash were installed at that time. This equipment included new ash collection equipment (i.e., ash tanks and sumps), a new ash transfer system (i.e., piping and ash sluice pumps) and new settling facilities (i.e., ash lakes). The ash collection and transfer equipment for Nos. 25 and 26 boilers were also re-engineered to make use of the new settling facilities. This reengineering included the modification of the ash sluice trench. The modified sluice trench was connected directly to the ash pit overflow outfall. The ash pit was removed from service.

#### **4.1.1 Circa 1948 Effluent Discharges**

Circa 1948, after New Unit No. 1 commenced commercial operations, non-contact cooling and wastewater effluents were managed for discharge by outfall to the Passaic River as follows:<sup>3</sup>

##### **4.1.1.1 Discharge Canal Outfall**

###### **(i) Turbine Room Discharges to Discharge Canal Outfall**

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<sup>3</sup>Effluent discharges are depicted graphically on Figures 2.3 through 2.7.

Saltwater

Discharge and drains from #1-6 Condensers.

Discharge and drains from #11-12 Condensate Coolers.

Discharge and drains from #3-6 Generator Air Coolers.

Discharge and drains from #2-6 Turbo Air Pumps.

Discharge and drains from #6A Steam Jet Air Pump.

Discharge and drains from #2-6 Turbine Oil Cooler.

Discharge and drains from #7 Turbine H<sub>2</sub> & Oil Coolers.

Cooling water and gland leak-off #2-6A Circulators.

Cooling water and gland leak-off #4-5-6 Saltwater Pumps.

Cooling water and gland leak-off #1-4-5 Air Compressors.

Sump pump and steam syphon discharges.<sup>4</sup>

Condensate - City or Service Water

Seal catch-all drains #11 & 12 Circulators.

Seal catch-all drains #11 & 12 Condensate Pumps.

Seal catch-all drains #3 & 7 Saltwater Pumps.

Seal catch-all drains #2-6A Condensate Pumps.

Drain from #1 Condenser Hotwell.

Overboard from #2-6A Condensate Pumps.

(ii) No. 2 Pump Room Discharges To Discharge Canal Outfall Indirectly Via Station Sewer

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<sup>4</sup>These discharges were re-routed in 1959 directly to the Passaic River.

System

Saltwater

Cooling water #1-3 Primary Feedwater Pumps.

Cooling water #1-3 Secondary Feedwater Pumps.

Turbine seal evactor #1-3 Secondary Feedwater Pumps.

No. 16 Sump Pump and syphon.

Condensate - City or Service Water

Gland leak-off catch-alls #1-3 Primary Feedwater Pumps.

Gland leak-off catch-alls #1-3 Secondary Feedwater Pumps:

Freeblows on steam headers.

Overboard and drain from #7 Open Drip Tank.

Overflow from #7 Turbine seals.

Steam Trap discharge from chemical mix tanks.

Overflow from #3 Station Hotwell.

Boiler Water

Drains from #25 & 26 Boilers.

Feedwater Treatment

Drains from #11-12 & Triplex Chemical Mix Tanks drain to sewer.

(iii) No. 3 Pump Room Discharges To Discharge Canal Outfall Indirectly Via Station Sewer System

Saltwater

Cooling water #6-8 Boiler Feedwater Pumps.

Steam syphon from trench.

Discharge from steam header manifolds.

Condensate

Gland leak-off catch-alls #6-9 Boiler Feedwater Pumps.

Drains from #6-9 Boiler Feedwater Pumps.

Overflow and drains #5-6-7 Open Heaters.

Overflow #3 Surge Tank.

Freeblows and traps from steam headers.

(iv) Fuel Oil Room Discharge To Discharge Canal Outfall Indirectly Via Station Sewer System

Saltwater

Cooling water #1-3 Fuel Oil Pump Reduction Gears.

Condensate

L.P. Steam Traps on #1-3 Fuel Oil Pump Turbines.

(v) Switch House Discharge To Discharge Canal Outfall Indirectly Via Station Sewer System

Sump pump discharges condensate from steam traps and seepage.<sup>5</sup>

(vi) Chlorine and Screen House Discharges to Discharge Canal Outfall

Saltwater

Wash water for Canal Screens.

Condensate

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<sup>5</sup>This line was rerouted directly to the Passaic River in 1959.

Heating system traps.

(vii) No. 1 Unit - Elev. 100'

Saltwater

Cooling water #11-12-13 Mills.

Drain and overflow #11-12 Acid Cleaning Tanks.

Overflow from seal #11-12 Ash Tanks.

Condensate

Catch-all drains #11-12-13 Boiler Feedwater Pumps.

Drain from #11 Drain Tank.

Drain from Condensate System.

Boiler Water

Drains from #1 Boiler.

#### **4.1.1.2 Ash Pit Overflow Outfall**

Circa 1948, the ash sluice trench was modified and the ash pit was removed from service.

The modified ash sluice trench was tied directly to the ash pit overflow outfall. Wastewater effluents routed to this modified outfall included the following:

- Surface runoff
- Laundry effluent
- Boiler Nos. 25 and 26 sluiceway effluents included boiler seal water overflow and miscellaneous leakage from piping and valves

- Surface water runoff and spillage from the chemical unloading area
- Miscellaneous roof and floor drains

#### **4.1.1.3 Cable Vault Sump Pump Outfall**

Groundwater and surface water runoff in an electrical cable vault located in the northwest section of property.

#### **4.1.1.4 Ash Lake Overflow Outfall**

- Overflow in ash lake from ash sluice from No. 1, No. 25 and No. 26 boilers
- Overflow in ash lake from Air Heater Wash Water from No. 1, No. 25 and No. 26 boilers

#### **4.1.1.5 Drainage Ditch**

Certain wastewater effluents were routed to a naturally occurring on-site drainage ditch which flowed to the Passaic River. Wastewater effluents routed to the drainage ditch included groundwater and surface water collections in the Station's other electrical cable vault.

Circa 1963, the following effluents were routed to the drainage ditch:

Boiler blowdown pit overflow

No. 8 combustion gas turbine building and equipment drain and non-contact cooling water  
Surface water runoff

#### **4.1.2 Circa 1970 Modifications to Effluent Discharge System**

Circa 1970, the Station modified certain of the processes associated with the management of cooling and wastewater effluents. The principal modification involved the installation of a 288,000 gallon chemical waste basin. The basin was an above ground structure with a liner and a dike. Approximate dimensions of the basin were 50 ft wide, 100 ft long, and 8 ft deep. The basin discharge was routed to the former ash pit overflow outfall (hereinafter referred to as Discharge Serial Number - "DSN" 342). Certain of the wastewater effluents were re-routed to the basin for primary treatment prior to discharge to the Passaic River via DSN 342. These wastewater effluents included wastewaters from low pressure boiler blowdown, high pressure boiler air heater washes and high pressure boiler washes. This modification coincided with the termination of the Station's use of coal as a fuel, and the removal of the ash lakes and ash lake overflow outfall from service. The final modification involved a change in practice with respect to chemical cleanings. Spent cleaning solutions generated by the chemical cleaning of major equipment were no longer discharged to the Passaic River, but disposed off-site.

#### **4.1.3 NPDES Permitting**

Subsequent to the enactment of the Federal Water Pollution Control Act of 1972 and

USEPA's assumption of primary responsibility for implementation of the NPDES permitting program, PSE&G submitted a revised application for an NPDES permit in November 1973. This revised application reflected the cooling and wastewater management system described above. The application was supplemented in May 1974, when PSE&G advised USEPA that the low pressure and certain of the high pressure steam electric generating equipment had been removed from service. These submissions identified discharges directly to the Passaic River consisting of: river water for condenser and condensate cooling and miscellaneous heat exchanger cooling; condensate and city water leakage from equipment; roof and floor drains; and traveling screen wash water. These submissions also identified other discharges (i.e., fireside washes, boiler blowdowns and air heater washes) to the chemical waste basin and then to the Passaic River. In January 1975, USEPA issued PSE&G NPDES Permit No. NJ0000565 for Station outfalls DSNs 341 and 342 with an effective date of January 30, 1975.

By letter dated August 15, 1978, PSE&G advised the USEPA that it had placed on inactive status all steam electric generating equipment at the Station. PSE&G advised that it would, however, have periodic batch discharges of approximately 10,000 gallons per year of boiler blowdown and drains associated with the continued operation of a low pressure boiler for house heating. PSE&G further advised that these wastewater effluents would be routed to the chemical waste basin for primary treatment prior to discharge to the Passaic River. Operations of the remaining low pressure boiler were terminated in 1979 with the installation of a package boiler for house heating. The low pressure boiler remained inactive and was eventually dismantled and removed from the site circa 1990.

PSE&G submitted an application for renewal of the Station's NPDES permit in August 1979. The renewal application generally identified two outfalls to the River, DSNs 341 and 342, and a sanitary sewer connection to PVSC. Effluent described as rainwater or groundwater seepage from Station building sumps was identified as being routed to the discharge canal (DSN 341) or the overboard line adjacent to the discharge canal for discharge to the Passaic River. Annual flow was estimated at 50,000 gallons per year. No pollutants were identified as being present since all equipment had been deactivated, drained and/or flushed. With respect to DSN 342, the application indicated that approximately 25,000 gallons per year would enter the chemical waste basin -- 10,000 gallons would have been effluent from boiler blowdown and boiler drains and 15,000 gallons would have been rain water that would collect in the basin. The application indicated that there would be no discharge via DSN 342 to the Passaic River since the basin's outlet valve would remain closed and the influents would be allowed to evaporate in the basin.

Circa 1980, Station operations consisted of electric power generation using combustion turbines. Net generating capacity was 664,333 kW. Electric generation by use of combustion turbine did not involve the discharge of cooling or wastewater effluents to surface waters. The one low pressure boiler then in operation had been removed from service, as the steam used for house heating was then being supplied by a package boiler. Blowdown from the package boiler was initially routed to the chemical waste basin where it was evaporated. The blowdown was subsequently routed to a flash tank in the Switch House basement where it was pumped to the sewage ejector pit for discharge to the PVSC system. Circa 1980, effluent discharges from the

Station generally were limited to stormwater and groundwater seepage in buildings. These effluents were being routed to existing outfalls for discharge to the Passaic River.

The NJDEP issued the Station a renewal permit in 1986 which authorized the Station to discharge non-process waste waters, specifically untreated stormwater, through three outfalls. The permit provided that neither discharge of non-contact cooling water via the discharge canal outfall nor discharge of process water via the former ash pit overflow outfall would be permitted without prior approval from NJDEP since the steam units had been retired.

PSE&G submitted a permit renewal application for the Station in 1990. Supplements to this application were filed. Circa 1990, field work activities associated with the demolition of the Station commenced. Demolition of the Station was completed in 1992. Equipment remaining at the Station includes combustion turbines, above ground fuel oil storage structures and electrical switching equipment located in the Switch House. The NJDEP issued a renewal NJPDES permit for the Station effective July 1995 permitting the discharge of stormwater from existing process areas associated with the combustion turbines and oil storage structures.

#### **4.1.4 Discharges to Passaic Valley Sewerage Commission**

In 1927, the Station's sanitary sewer system was connected to the PVSC System. Circa 1970, wastewaters from the Station's laundry were also routed to the PVSC.

In 1975, the PVSC advised PSE&G that all industries were required to remove incompatible pollutants prior to discharge to the PVSC system and requested certain information regarding Essex's discharges to the PVSC and to the Passaic River. PSE&G's response indicated that the only discharge to the PVSC from the Station was sanitary wastes. PSE&G supplied analytical results for sanitary waste waters collected at its Hudson Generating Station since no data were available relative to the effluent discharged from Essex. PSE&G stated that the Hudson data were deemed to be representative of the sanitary waste effluent from Essex. PSE&G provided analytical data used in NPDES applications relative to the quality and quantity of pollutants present in effluents discharged to the Passaic River via two outfalls: (1) the "Main Discharge Canal" which consisted of river water treated with chlorine used for non-contact cooling; and (2) the "Overboard Line" which consisted primarily of blowdown from the low pressure boiler used for house heating and, occasionally, wash waters from air heater and fireside washes.

The quantity of effluent discharged to PVSC decreased as Station operations were removed from service. In 1988, PVSC requested and PSE&G completed a Questionnaire for Potential Large Industrial User. PVSC forwarded to PSE&G in 1989 an application for a sewage connection permit. PSE&G completed the application, advising the PVSC that the Station did not produce process wastes and there were no manufacturing process discharges to the PVSC system. The Station's sanitary sewer system continues to discharge to the PVSC system.

## 4.2 Air Permits and Emissions

New Jersey amended its air pollution control statute in 1967 to provide, in pertinent part, that “no person shall construct, install, or alter any equipment or control apparatus” unless an application had been filed and the NJDEP had issued a permit to construct and/or a certificate to operate (“Air Permit”) such equipment or apparatus. The statute also provided the NJDEP with the requisite discretion to phase in the statutorily mandated air permit program. Commencing in 1968, the N.J. Department of Health (“NJDOH”) and then the NJDEP adopted implementing regulations under N.J.A.C. 7:27-8.1, et seq. specifying the types of equipment requiring an air permit, if such equipment were installed, constructed or altered after the dates specified in the regulations. In effect, the regulations exempted from the air permitting requirements equipment which was constructed or installed (and not altered) after a given date (“Grandfathered Equipment”).

Section 2.0 above describes the various types of equipment at Essex and provides the installation dates for each. Although the types of equipment at Essex (e.g., boilers, fuel oil tanks) were among the types of sources requiring air permits under N.J.A.C. 7:27-8.1 et seq., the equipment was deemed Grandfathered Equipment in that it was constructed prior to the designated date triggering an air permit.

Although much of the equipment at Essex was not subject to the requirements of N.J.A.C. 7:27-8.1 et seq., air permits have been obtained for the following Station equipment:

- PSE&G installed an Auxiliary Boiler, commonly referred to as a "House Heating Boiler" in 1979. The boiler had a maximum heat input of 4.0 MMBtu/hr. PSE&G applied for and was issued an Air Permit for this boiler in 1979. The boiler was removed from service in 1994, and its Air Permit was canceled.
- PSE&G installed an 8,000 gallon fuel oil tank in 1979 to serve the House Heating Boiler referred to as the "No. 2 Fuel Oil Tank at the Switch House". Although an Air Permit had been issued for this tank, a subsequent review indicated that no permit was actually required for this tank because it had a capacity of less than 10,000 gallons and stored a volatile organic liquid with a vapor pressure of less than 0.02 pounds per square inch absolute ("psia") at standard conditions. This tank was removed from service in 1994 and the Air Permit was canceled at or about that time.
- Combustion turbine Unit No. 9 was replaced in 1990 with a new state-of-the-art combustion turbine unit ("New Unit No. 9"). The Station applied for an Air Permit in 1989 to operate New Unit No. 9 using natural gas. PSE&G conducted ambient air quality studies in connection with the preparation of the application. Mathematical modeling, which relied upon manufacturer's emission data and proposed unit operations, was used to determine whether the proposed Unit 9 would cause or significantly contribute to an exceedance of an ambient air quality standard. In conjunction with the Unit 9 modeling studies, less rigorous modeling studies were conducted for Units 10, 11 and 12, using

estimates of exhaust gas characteristics as model inputs. The modeling studies for Units 10-12 was performed to identify issues that might arise if the modeling study for Unit 9 would have predicted the potential to cause an exceedance of a significant impact level.

- NJDEP issued an Air Permit/Certificate in 1990 for New Unit No. 9 which was amended in 1993, based upon PSE&G's supplementary application, to allow New Unit No. 9 to burn natural gas as the primary fuel and distillate oil as a secondary fuel. This Air Permit, in part, requires stack testing every five years for NO<sub>x</sub>, Carbon monoxide ("CO"), non-methane hydrocarbons, total suspended particulates ("TSP") and PM-10. In addition, it required the installation and operation of a continuous emission monitor ("CEM") to record NO<sub>x</sub>, CO and O<sub>2</sub> emission data. Annual emission reports for the emission years 1990 and 1992 through 1995; and data from the CEMs for the years 1990 through 1995 are available upon request.

In early 1990, Congress enacted the Clean Air Act Amendments of 1990 ("CAAA"). New Jersey also adopted major amendments to its air pollution control statute in 1993. Each of these acts and their implementing regulations established supplemental requirements and/or standards relative to the control of air pollution, certain of which were applicable to the Station.

Title V of the CAAA requires states to develop and implement facility-wide operating permit programs. The USEPA and NJDEP promulgated regulations establishing facility-wide operating permit programs ("Operating Permit"). In anticipation that the NJDEP might require

applicants for Title V permits to submit ambient air quality analyses (for certain criteria pollutants and TSP) with such applications, PSE&G conducted preliminary, in-house modeling studies for Unit Nos. 10, 11 and 12 between 1992 and 1995. Sensitivity analyses were conducted in 1994 and 1995 to address, among other things, uncertainties in model inputs, (e.g., emission rates, exhaust gas flow and temperature and exhaust gas velocity) the complexity of the arrangement of structures surrounding the stacks, and changes in stack heights.

PSE&G, pursuant to the Operating Permit regulations, submitted an operating permit application for all significant sources at Essex to the NJDEP in August 1995. The final regulations adopted by NJDEP did not require the conduct of ambient air quality studies. NJDEP advised PSE&G in January 1996 that its application was timely filed and administratively complete. The application is currently undergoing technical review by the NJDEP.

In addition to the requirements to apply for an Operating Permit, the CAAA, the 1993 New Jersey Act and their implementing regulations impose other requirements relative to the control of air-borne emissions from Essex. In this regard, PSE&G has, among other things: (1) made submittals to NJDEP relative to applicable NO<sub>x</sub> RACT requirements including a system-wide NO<sub>x</sub> Emissions Averaging Plan which was approved by NJDEP in November 1995; (2) made submittals to NJDEP relative to applicable volatile organic compounds ("VOC") RACT requirements; and (3) filed requisite data and reports with USEPA and NJDEP.

PSE&G also has conducted a limited number of stack tests at Essex. These include: (1) a

series of stack tests on one stack at Unit 10 was performed to determine whether the TSP emission rates were typical of PSE&G's fleet of combustion turbines and the extent of which TSP is present in stack gases due: to the combustion process; background concentrations in the ambient air; or particulates added to the ambient air that passes through the housing surrounding the combustion turbine; and (2) a special study to investigate the reentrainment of exhaust gases through the combustion turbines' air intakes.

Documents, correspondence, data, and written studies are available for inspection.

#### **4.3 DPCC/DCR/SPCC Programs**

Beginning in the mid 1970s with the promulgation by the USEPA of regulations pursuant to Section 311 of the Clean Water Act, PSE&G was required to prepare a Spill Prevention Control and Countermeasures ("SPCC") Plan for Essex. Pursuant to these USEPA regulations, PSE&G developed and implemented an SPCC Plan for the Site which set forth specific information with respect to the facilities, equipment and personnel at Essex relating to the storage of oil at the Station as well as preventative measures and spill response plans for any spill of oil into navigable waters.

Subsequently, the NJDEP developed a substantially similar regulatory program pursuant to its authority under the New Jersey Spill Compensation and Control Act. This state regulatory program, which is codified at N.J.A.C. 7:1E-1 et seq., required PSE&G to prepare and to file

with the NJDEP a Discharge Prevention, Containment and Countermeasures ("DPCC") Plan and a Discharge Cleanup and Removal ("DCR") Plan. The substance and purpose of the DPCC and DCR Plans required by the NJDEP and the SPCC Plan required by USEPA were essentially similar; however, the DPCC/DCR regulations expanded the scope of the program to include discharges of hazardous substances.

Subsequent to the adoption of these regulations, PSE&G prepared a consolidated SPCC and DPCC/DCR Plan. This consolidated Plan was submitted to the NJDEP in 1977. Subsequent to this submission, the Station prepared revised Plans in response to a series of NJDEP comments. The Plan received final NJDEP approval in 1986. A list of SPCC/DPCC/DCR applicable storage and processing equipment (including underground storage tanks ("USTs")) from circa 1980, through January 1996 are presented on Table 3.37. The list does not include SPCC/DPCC applicable storage and processing equipment associated with the steam electric generating facilities which had been removed from service as of 1978.

PSE&G has periodically updated, revised and supplemented its SPCC/DPCC/DCR Plan for the Station in accordance with the requirements of applicable state and federal regulations. These are on-going regulatory programs and PSE&G continued to have contact with NJDEP and, from time to time, USEPA concerning issues relating to its SPCC/DPCC/DCR Plan for the Station.

Pursuant to the Oil Pollution Act of 1990 ("OPA"), PSE&G was required to submit a

Facility Response Plan ("FRP") for Essex in that the Station was, as of the applicable trigger date, a non-transportation-related onshore facility. PSE&G submitted its FRP to USEPA on February 18, 1993.

Upon completion of its initial review in June 1993, USEPA requested additional information. This information was submitted in July 1993. In July 1994, USEPA advised PSE&G that it had conducted another initial review and requested additional information. This information was submitted in September 1994. As of this date, PSE&G has not received notice of final agency action with respect to the FRP.

Available correspondence by and between PSE&G and relevant regulatory agencies relating to SPCC/DPCC/DCR/OPA issues is available for inspection.

#### **4.3.1 Spill Discharge History**

The Station was an industrial operation that involved the handling and storage of materials (primarily coal and oil). Spills and discharges that may have involved releases to the environment occurred. Housekeeping policy and practice was directed at prevention, early detection and expeditious corrective action. While PSE&G's file search is not yet complete, this section presents a summary of discharge and spill incidents for which documentation has been located to date, involving releases to the environment as detailed below:

- In June 1973, solidified No. 6 Fuel Oil (Bunker C Fuel Oil) in a fuel oil heater became heated, liquefied, and drained into a sump tank in the fuel oil room causing the tank to overflow. The oil that overflowed the tank entered the Station's drain system and flowed into the Passaic River. Spill response measures were performed by a contractor. There is no documentation available estimating the quantity of material discharged. The discharge was reported to the United States Coast Guard ("USCG") which responded. Corrective actions were implemented with USCG oversight. There is no record that sampling of any media was performed. The USCG issued a notice of violation ("NOV") which was resolved.
- In July 1973, No. 6 Fuel Oil leaked from a fuel oil heater valve causing oil to enter the Station's drain system and flow into the Passaic River. Spill response measures were performed by a contractor. There is no documentation available estimating the quantity of material discharged. The discharge was reported to the USCG, the USCG responded, and corrective actions were implemented with USCG oversight. There is no record that sampling of any media was performed. The USCG issued a NOV which was resolved.
- In November 1974, No. 6 Fuel Oil leaked from a valve on a fuel oil heater, entered the Station's drain system and flowed into the Passaic River. Available information indicates that approximately 40 gallons of fuel oil were discharged. Spill response measures were performed by Station personnel. The discharge was reported to the USCG. The USCG responded, and corrective actions were implemented with USCG oversight. There is no

record that sampling of any media was performed. The USCG issued a NOV which was resolved.

- In October 1975, a thin narrow film of material was observed along the dock front. As the tide receded, it appeared that the material was entering the river from DSN 342. The material was described as a pale, bluish-gray substance; however, there was not enough material present to collect a full sample. The material lacked the characteristic rainbow spectrum sheen that an oil droplet displays over water. Further investigations suggested that the material was a detergent, cleaning agent or non-petroleum type substance which had entered the flow drain system of the low pressure boiler area. The USCG, NJDEP, USEPA, and the PVSC were notified by Station personnel. The estimated quantity of material was one to two quarts. Station personnel cleaned up the substance. One sample was collected; however, due to the limited sample volume, all that could be concluded was that the material was not oil. Available Station records do not indicate any further regulatory actions as a result of the incident.
- In January 1976, during a routine inspection by representatives of the PVSC, a black oily liquid was observed being pumped from a manhole near the Station onto the ground where it then flowed to Lawyers Ditch, a tributary of the Passaic River. The quantity and constituent substances of this discharge are unknown. PSE&G employees complied with the PVSC request to cease the pumping operation immediately. It is unknown whether any remedial actions were taken with respect to this discharge.

- In October 1989, PSE&G notified the NJDEP hotline of a small leak detected at Fuel Oil Tank No. 1 during a tank cleaning associated with the planned retirement of the tank. Several gallons of No. 6 Fuel Oil appeared outside the tank in the six inch area between the tank and its concrete containment. The oil most likely appeared because the steam and high pressure water was used to remove solidified No. 6 Fuel Oil from the tank. The oil was then forced out of some of the small corrosion openings that had developed around rivets which were part of the tank's construction. PSE&G cut holes in the tank floor to inspect the ground under the tank. This inspection verified that oil leakage was limited and that there was no potential hazard to the ground water or surface water.

When Fuel Oil Tank No. 1 was demolished in September 1990, PSE&G re-examined the ground under the tank and found oil-soaked soil in the containment at the circumference of the tank, which was collected in plastic bags and placed in the Station's hazardous waste dumpster. There was some oil-soaked soil in the area of the tank sump. This area did not have a heavy concentration of oil; however, PSE&G removed several cubic yards of material, excavating as much as two feet below grade. There are no other records related to this spill.

- In June 1990, a kerosene leak from an above ground storage tank was detected. The kerosene that leaked from the tank was contained in the tank's secondary containment system, an earthen dike with a claymax liner. Approximately 3,000 gallons of kerosene

entered into the secondary containment system. Response measures were initiated by Station personnel and completed by a contractor. None of the material was discharged to the ground and/or to the waters of the State. The leak was reported and actions to curtail the leak and upgrade the tank to prevent future leaks were implemented with NJDEP oversight. Sampling of environmental media was not performed.

- In July 1990, a discharge of No. 4 Fuel Oil occurred at a relief plug in a pipeline pig-catcher being used in an Amerada Hess fuel oil transfer pipeline located at the Station. As a routine practice, Amerada Hess used No. 4 Fuel Oil to flush its transfer pipeline following delivery of No. 6 Fuel Oil to the Station. Discharge response measures were initiated by Amerada Hess personnel and completed by an Amerada Hess contractor. Approximately 800 gallons of No. 4 fuel oil were discharged to the ground. None of the material migrated to the Passaic River. The discharge was reported to NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
- In January 1991, a leak of kerosene occurred in a below ground fuel oil delivery line for a kerosene storage tank. Approximately 13,000 gallons of kerosene were discharged into the ground. Seepage from the discharge migrated to the Passaic River. Discharge response measures were initiated by Station personnel and completed by a contractor. The discharge was reported to NJDEP, USCG and USEPA and corrective actions were implemented with NJDEP and USCG oversight. The USCG issued a NOV which was

resolved. The NJDEP also issued a NOV requiring PSE&G to implement a remedial action program. PSE&G resolved the NOV by entering into a Memorandum of Agreement ("MOA") pursuant to which a site remediation program was implemented. The site remedial program included limited media characterization, excavation and off site disposal of contaminated soils and a groundwater recovery and monitoring program; the treated groundwater was discharged to the Passaic River. PSE&G completed the site remedial program and the NJDEP issued PSE&G a No Further Action ("NFA") Letter in June 1994.

- In May 1992, a discharge occurred in an aboveground portion of a 26 kV cable dielectric oil pipeline. Approximately 40 gallons of dielectric transil oil were discharged to the ground surface. The discharged material did not migrate to the Passaic River. Response measures were initiated by Station personnel. The discharge was reported to NJDEP and corrective actions were implemented. Sampling of environmental media was not performed. No violation was issued.
- In May 1992, a leak occurred in a drum containing transil oil causing a discharge of approximately one gallon of transil oil to the ground. The discharged material did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.

- In July 1992, petroleum hydrocarbon-contaminated soil was encountered in an excavation. The source of the contamination was not identified. The discharge was reported to NJDEP and corrective actions were implemented. Corrective actions involved the excavation of soils in a discrete area visibly contaminated with petroleum hydrocarbons. Sampling of environmental media was not performed.
- In November 1992, a leak occurred in a fuel oil line for a combustion turbine unit. Approximately 50 gallons of kerosene were discharged into the ground. The kerosene did not migrate to the Passaic River. Discharge response measures were initiated by Station personnel and completed by a contractor. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
- In November 1992, a vent valve from an overhead section of a fuel oil line to a combustion turbine unit opened causing a discharge of approximately 3,000 gallons of kerosene to the ground. The kerosene did not migrate to the Passaic River. Discharge response measures were initiated by Station personnel and completed by a contractor. The discharge was reported and corrective actions implemented with NJDEP oversight. Sampling of environmental media was performed. PSE&G implemented a site remedial program under an MOA with the NJDEP. The program included post-excavation soil sampling. A Remedial Action Report is currently being prepared.

- In January 1993, a leak occurred in an above ground purge fuel oil line for one of the combustion turbine units. Approximately 15 gallons of kerosene were discharged to the ground surface. The kerosene did not migrate to the Passaic River. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
- In September 1993, a transformer cooling radiator failed causing a discharge of approximately 900 gallons of mineral oil to the ground surface. The extent of the discharge was limited by the presence of a firewall under the transformer. The mineral oil did not discharge to the Passaic River. Discharge response measures were initiated by Station personnel and completed by a contractor. The discharge was reported and corrective actions implemented with NJDEP oversight. Sampling of environmental media was performed. PSE&G implemented a site remedial action program under an MOA with the NJDEP. The program included the excavation and off-site disposal of contaminated soils. A Remedial Action Report for this remedial program was submitted to the NJDEP. NJDEP issued a NFA letter in June 1996.
- In October 1993, approximately 30 gallons of transil oil were discharged to the ground during the course of an underground electrical transmission line repair project. The transil oil did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.

- In January 1994, a leak occurred in an above ground fuel pipeline causing the discharge of approximately 5 gallons of kerosene to the ground surface. The kerosene did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
  
- In March 1994, a leak occurred in an above ground fuel pipeline causing the discharge of approximately 5 gallons of kerosene to the ground surface. The kerosene discharged did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
  
- In June 1994, a discharge of purge oil from an above ground fuel oil line occurred due to the failure of a fuel pump. Approximately four gallons of kerosene were discharged to the ground surface. The kerosene did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
  
- In August 1994, a discharge of coolant from a gauge glass on a combustion turbine unit cooling tower occurred as a result of an equipment malfunction. Approximately two gallons of oil were discharged to the ground. The coolant did not migrate to the Passaic

River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.

- In September 1994, a kerosene residue was observed on the ground surface. The source of the residue was not identified. The quantity of residue was estimated at approximately two gallons. The residue did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
- In October 1994, a 230 kV above ground oilstatic cable piping failed causing a discharge of mineral oil to the ground surface. Approximately 15 gallons of mineral oil were discharged. The mineral oil did not migrate to the Passaic River. Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP and corrective actions were implemented. Sampling of environmental media was not performed.
- In May 1995, during the demolition of the old Unit No. 9 combustion turbine, subsurface deposits of lubricating oil and kerosene were encountered. Approximately 2,900 gallons of lubricating oil and water were encountered. No estimate of the quantity of kerosene encountered is available. The discharged materials did not migrate to the Passaic River.

Discharge response measures were performed by Station personnel. The discharge was reported to the NJDEP. No NOV was issued. Sampling of environmental media was performed. PSE&G implemented a site remedial action program under a MOA with the NJDEP. The program included the removal of the free product and excavation and off site disposal of contaminated soils. PSE&G submitted a Remedial Action Report to NJDEP in July 1996.

Available correspondence by and between PSE&G and relevant regulatory agencies concerning these spill incidents is available for inspection. Available reports concerning sampling of environmental media and any reports of corrections are also available for inspection.

#### **4.4 Hazardous Waste Management**

The Resource Conservation and Recovery Act ("RCRA") provides the basic framework for regulation of hazardous waste. RCRA was adopted in 1976 as a revision and expansion of the Solid Waste Disposal Act of 1965. It introduced a nationwide program for management of hazardous wastes by controlling the generation, transportation, treatment, storage and/or disposal of hazardous waste through a comprehensive system of hazardous waste management requirements. The RCRA statute, inter alia, directed USEPA to develop standards for handling, tracking and disposing of hazardous wastes. USEPA adopted certain implementing regulations in 1980.

RCRA regulations create an elaborate system for tracking hazardous waste from the time it is generated until its ultimate disposal. RCRA divides the universe of entities that shepherd hazardous waste through its life cycle into categories. Generators are one such category and include "[a]ny person, by site, whose act or process produces hazardous waste." Generators bear responsibility for determining whether their solid waste is hazardous. Upon making such a determination, they must: (1) obtain a hazardous waste identification number from USEPA; (2) carefully package and label wastes; (3) ship them to an authorized treatment, storage and disposal facility; and, (4) prepare a manifest which tracks the waste from the generator's site to its ultimate disposal site. Generators must biennially submit reports on waste generating activities.

RCRA provides that States may establish their own hazardous waste programs so long as they meet or exceed minimum USEPA requirements. Over period from 1978 through 1981, New Jersey adopted regulations implementing a hazardous waste program consistent with federal requirements, (See N.J.A.C. 7:26-1 et seq.). Pursuant to the New Jersey Solid Waste Management Act (N.J.S.A. 13:1E-1 et seq.) These regulations imposed requirements on generators associated with, inter alia, the management for off-site disposal of hazardous wastes. These regulations require, inter alia, that generators: (1) have an USEPA generator I.D. No.; (2) complete a USEPA/NJDEP-approved hazardous waste manifest form in connection with the off-site disposal of hazardous wastes; (3) file with the NJDEP an annual report of such shipments; and, (4) retain manifests and annual reports for a period of three years.

In 1980, the Station obtained a USEPA generator number (No. NJD000574000). The Station submitted Hazardous Waste Generator Annual Reports to the NJDEP thereafter.

The Station's Hazardous Waste Manifests for the years 1989 through 1995 and Hazardous Waste Generator Annual Reports for the years 1984 through 1995 are available for inspection.

#### **4.5 Underground Storage Tanks**

New Jersey enacted a statute in 1986 (as amended in 1990) providing for, inter alia, the registration of underground storage tanks ("USTs"). Station USTs were identified in connection with the preparation of the SPCC/DPCC/DCR Plan (see Table 3.37). The Station initiated the registration process for certain of the USTs then at the Station. At that time, there were twenty-five USTs at the Station.<sup>6</sup> These USTs are identified in Table 3.39.

The twenty-five USTs fall into three categories: twenty-one purge oil collection USTs for the combustion turbine generators; three USTs used for vehicle fuel storage; and one UST used for lube oil storage.

With respect to the three vehicle fuel storage USTs, records indicate the following: two

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<sup>6</sup>As discussed in Section 3.6.5 above, a 1,000 gallon steel UST for diesel fuel oil storage had been installed circa 1924. Records are not available with respect to the removal of this tank.

were of steel construction and one was fiberglass; the 3,000 gallon diesel UST was installed in 1951; and there is no indication of an installation date for the other two USTs. Records relating to the regulatory registration and compliance with then-applicable NJDEP regulatory requirements with respect to these three USTs are incomplete. There is an indication that the 3,000 gallon diesel UST was registered pursuant to NJDEP regulations. In April 1988, all three of these vehicle fuel USTs were removed, according to available records.

The lube oil UST was discovered in 1989 under the coal tower. It was cleaned and removed by a contractor in September 1989. There are no records indicating whether it was registered, nor is there any indication of its size or condition.

The twenty-one purge oil USTs were installed for the combustion turbines. These USTs were not initially registered with the NJDEP because, as flow through process tanks, they were exempt from regulation under then-applicable NJDEP rules. Records indicate that circa 1990, five of these USTs were removed. The remaining sixteen USTs were registered with the NJDEP after a regulatory amendment required such registration. In 1992, PSE&G instituted closure and removal of these sixteen USTs pursuant to applicable NJDEP regulations and with NJDEP oversight. Site assessment work related to these UST removals is on-going.

Relevant records relating to Station USTs are available for inspection.

#### **4.6 Floods, Fires and Other Incidents**

Based on available information, several floods, fires and explosions occurred at Essex over the operating life of the Station. These incidents are summarized below.

### **Explosion and Fire -- A & B Group Selector Oil Switches and Equipment**

An explosion and fire occurred on the "A & B Group Selector Oil Switches and Equipment" on May 16, 1927. Damage was extensive, necessitating the replacement of nine barrier walls in the oil circuit breaker compartments and forty-two cell doors. Repairs were made to the A & B Group selector oil switches, disconnecting switches, current transformers, control wiring, cable compartments, and compartment doors in the 4th and 5th floors of the Switch House.

### **Fire on Fifth Floor Switch House**

A fire occurred in the Switch House at Essex on December 28, 1936. Relevant file information describing the maintenance work that was performed to repair the damage to the Switch House is available. Section 3.8 above provides additional information relative to these repairs.

### **Fire on Sixth Floor Switch House**

On August 19, 1938 at 6:38 p.m., a bus short circuited, igniting a fire between Nos. 2 and

3 phases on the new M-group tie bus on the sixth floor of the Switch House. This fire damaged the 13,000 volt bus, bus insulators, disconnecting switches, and compartment structures and doors. Repairs were completed on or before September 21, 1938.

### **Dock Collapse**

On September 14, 1948, the dock collapsed between the coal tower and discharge canal. Although the dock had been recapped in 1937, the support piles had been installed in 1915. As a safety precaution, the small section of the dock which remained after the collapse was removed. Both sections of the dock were completely rebuilt.

### **Storm Damage**

Various ancillary equipment and building structures (e.g., cracked lights and windows, building roofs, screen doors), were damaged during a severe wind storm which took place on November 25, 1950.

### **Flood**

Many areas of the Essex property were flooded during the "NorEaster" (Northeastern) storm of March 6, 1962. During this storm, available records indicated that river elevation in the vicinity of the Harrison Gas Plant upriver of Essex reached 7.78 ft. above mean sea level. Cars

parked on Station property were caught in waters which reached the elevation of a standard car's steering wheel.

#### **No. 6 Unit Condenser Explosion**

An explosion occurred in the Unit No. 6 condenser circa 1971. No records, other than photographs, have been located relative to this event.

#### **Unit No. 10 Fire, 103 Inlet Filters**

A fire occurred on No. 10 Unit, 103 Inlet Filters on June 27, 1994 at 2:39 p.m. The local fire department responded and extinguished the burning filters. No release of materials was reported.

#### **No. 9 Gas Turbine Fire**

The old Unit No. 9 combustion turbine was destroyed by fire on January 3, 1989. The fire began at approximately 8:00 p.m. when lube oil ignited. Foam and chemical fire protection systems were activated. Station personnel used a 150 lb cylinder of "K" dry chemical on the fire. The Newark Fire Department was called and the fire was extinguished by approximately 8:45 p.m. The unit was damaged beyond repair and was eventually demolished in 1995. A New Unit No. 9 was constructed in the early 1990s to replace the damaged unit.

## **Flood**

In December 1992, a storm caused excessively high tides. Flood waters inundated the Station. Available information indicates that these flood waters did not rise over the level of any secondary containments. There is no record of a release of a hazardous substance as a result of this flood.

### **4.7 Environmental Media Studies/Analyses**

Analytical data from environmental media sampling at Essex may be summarized as follows:

- In November 1989, approximately 6,000 cu. yd. of soil was excavated in connection with the preparations for New Unit No. 9 foundation construction. Analysis was performed to conduct a waste classification pursuant to NJDEP solid waste regulations. Excavated soils were classified as ID 27 non-hazardous waste and recycled as asphalt aggregate.
- As a result of a kerosene delivery pipe failure discovered on January 28, 1991, approximately 13,000 gallons of kerosene was discharged into the ground. During remediation of the discharge, periodic groundwater monitoring was conducted. Final groundwater sampling results submitted to NJDEP in 1992 reported levels below published standards for groundwater classification Class IIA cleanup standards. NJDEP

has issued a NFA letter.

- During demolition of the Steam Station in 1991, PCBs were found to be present in several pieces of electrical switching equipment for No. 1 Unit. The foundation and surrounding soil were sampled. The sampling from the concrete foundation had elevated levels of PCBs which were remediated. Post-remediation sampling indicated that the remaining concrete and surrounding soil levels were below NJDEP cleanup guidance levels for residential areas.
- Post-excavation soil samples taken in an area impacted by a discharge of 3,000 gallons of kerosene in November 24, 1992 indicated non-detects for VOCs. A Remedial Action Report is currently being prepared.
- Following the remediation of the area under a 132-1 transformer phase which had a radiator fail in 1993, post excavation samples were taken. A Remedial Action Report was submitted to NJDEP in May 1996.
- During demolition of old No. 9 Unit in April 1995, approximately 2,900 gallons of oil and water were found under the foundation. Kerosene was also detected during post-excavation sampling and additional soils were excavated. The combustion turbine, including the foundation, was demolished and the soil surrounding the unit was excavated. Post-excavation soil and groundwater indicated that residual levels were below NJDEP

residential cleanup guidance levels. A Remedial Action Report was submitted to the NJDEP in July 1996.

Groundwater monitoring wells and post-excavation soil and groundwater samples were collected and analyzed under the NJDEP-approved closure plan associated with the closure of sixteen purge oil collection tanks. Activities relative to the closure plan are continuing under NJDEP guidance.

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CERTIFICATION OF ANSWERS TO REQUEST FOR INFORMATION

State of New Jersey :  
County of Essex : ss.

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document (response to EPA Request for Information) and all documents submitted herewith, and that based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the submitted information is true, accurate, and complete, and that all documents submitted herewith are complete and authentic unless otherwise indicated. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. I am also aware that my company is under a continuing obligation to supplement its response to EPA's Request for Information if any additional information relevant to the matters addressed in EPA's Request for Information or the company's response thereto should become known or available to the company.

Horace G. Campbell  
NAME (print or type)

Manager, Site Remediation, Project Development - Fossil  
TITLE (print or type)

  
SIGNATURE

Sworn to before me this 13th day  
of August, 1996.

Rosario Del Tufo - Di Iorio  
Notary Public

**Rosann DeTuto-Diorio**  
**NOTARY PUBLIC OF NEW JERSEY**  
**My Commission Expires May 14, 1999**



**Table 3.1****Low Pressure Units - Operating Parameters**

<b>Low Pressure Boilers</b>					
<b>Year Installed</b>	<b>Manufacturer</b>	<b>HP</b>	<b>Pressure (psi)</b>	<b>No. of Boilers</b>	<b>Fuels<sup>1</sup></b>
1915	B&W	1373	242	4	Coal, Oil
1917	B&W	1278	242	8	Coal, Oil
1919	B&W	1278	242	4	Coal, Oil
1923	B&W	1859	242	2	Coal, Oil
1924	B&W	1859	242	6	Coal, Oil
<b>Low Pressure Steam Turbine/Generators</b>					
<b>Year Installed</b>	<b>Manufacturer</b>	<b>HP</b>	<b>KW</b>	<b>Volts</b>	<b>Maximum Generator Name Plate Rating (KW)</b>
1915	GE	33,500	25,000	13,200	22,500 KW
1915	GE	33,500	25,000	13,200	22,500 KW
1918	GE	53,600	40,000	13,200	40,000 KW
1923	GE	47,300	35,000	13,200	36,000 KW
1923	GE	47,300	35,000	13,200	36,000 KW
1924	GE	56,600	40,000	13,200	36,000 KW

B&W = Babcock & Wilcox  
GE = General Electric  
HP = Horsepower  
psi = Pounds Per Square Inch  
KW = Kilowatts

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<sup>1</sup>Essex began using No. 6 Fuel Oil, Circa 1933.

Table 3.2

**Raw Materials  
Low Pressure Boilers  
Essex Generating Station 1915 to 1978**

<b>Materials</b>	<b>Use and Description</b>	<b>EPA Letter</b>	<b>CERCLA Listed Substance</b>
<b>Fuels</b>			
Bituminous Coal (WVa & PA Sources)	Boiler Fuel	*	
No. 6 Fuel Oil	Boiler Fuel	*	
Combustion Air	Boilers and Combustion Turbines		
<b>Fuel Additives or Treatments</b>			
Coal Trol (22% Phosphoric Acid)	May have been used for treatment of coal piles to prevent freezing		*
<b>Boiler Water Treatment Chemicals</b>			
Sodium Carbonate (Soda Ash)	Boiler Water Treatment, pH Adjustment		
Sodium Sulfate	Boiler Water Treatment	*	
Phosphoric Acid	Boiler Chemistry Control, Adjustment of Phosphate Concentration		*
Sodium Hydroxide (Caustic)	Boiler Water Treatment and as Neutralizing Agent		*
Disodium Phosphate	Boiler Water Treatment, Phosphate Addition		*
<b>Chemical used for Equipment Cleanings</b>			
Hydrochloric Acid	Condenser Cleanings		*
NEP 22	Condenser Cleanings		
Sodium Cyanide	Condenser Cleaning, Oxide Removal (one cleaning only)	*	*
Oakite (Trisodium Phosphate)	Condenser Cleaning, Oxide Removal (one cleaning only)		*
Caustic Soda	Neutralizer (one cleaning only)		*
<b>Water Sources</b>			
River Water	Cooling and Various In-Plant Uses		
Newark City Water (potable)	Boiler Makeup and Sanitary Uses		
<b>Non-Contact Cooling Water Treatment Chemicals</b>			
Chlorine (circa 1933)	Non-Contact Cooling Water Condenser, Biofouling Control		*

**Table 3.3**

**Typical Low Pressure Boiler Chemistry Limits  
Essex Generating Station 1915 to 1978**

<b>Constituent</b>	<b>Limit or Range</b>
Phosphate	60.0 - 120.0 ppm
Hydroxide	0 - 5 ppm
pH	11.0 - 11.3
Sulfate to Alkalinity Ratio	3.1
Total Solids	1,500 ppm

Ref: ESSEX Operating Data

Table 3.4

**Boiler Blowdown  
Low Pressure Boilers  
Essex Generating Station 1915 to 1978**

Substance	Typical Concentration (ppmw)
Total Dissolved Solids	499.0
Suspended Solids	1.0
Calcium Carbonate $\text{CaCO}_3$	2.83
Magnesium Carbonate $\text{MgCO}_3$	4.83
Sodium Carbonate $\text{Na}_2\text{CO}_3$	10.44
Sodium Hydroxide $\text{NaOH}$	34.72
Sodium Chloride $\text{NaCl}$	142.0
Sodium Sulphate $\text{Na}_2\text{SO}_4$	238.0
Trisodium Phosphate $\text{Na}_3\text{PO}_4$	42.8
Silica $\text{SiO}_2$	19.5
Iron and alumina	0.1
pH	10.5
Organic Matter	18.2

ppmw = parts per million by weight

Ref - Analysis of PSE&G Low Pressure Boiler Blowdown - Cyrus WM. Rice & Company April 1937

Table 3.5

## Fuels / Generation Statistics Essex Generating Station

STEAM UNITS						COMBUSTION TURBINES			COMMENTS
YEAR	BITUMINOUS COAL (TON) **	GAS (MCF)	OIL BARRELS	NET GENERATION (Kwh)		GAS (MCF)	OIL BARRELS	NET GENERATION (Kwh)	
1915	1,766	N/A	N/A	823,000		N/A	N/A	N/A	
1916	109,367	N/A	N/A	153,951,500		N/A	N/A	N/A	
1917	160,561	N/A	N/A	232,105,000		N/A	N/A	N/A	
1918	222,397	N/A	N/A	288,584,000		N/A	N/A	N/A	
1919	243,512	N/A	N/A	294,481,100		N/A	N/A	N/A	
1920	319,149	N/A	N/A	380,006,900		N/A	N/A	N/A	
1921	242,887	N/A	N/A	333,280,000		N/A	N/A	N/A	
1922	282,011	N/A	N/A	389,214,000		N/A	N/A	N/A	
1923	372,443	N/A	N/A	513,566,900		N/A	N/A	N/A	
1924	450,140	N/A	N/A	675,979,861		N/A	N/A	N/A	
1925	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	24 Boilers in service
1926	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1927	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1928	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1929	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1930	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1931	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1932	* 411,291	N/A	N/A	618,000,000		N/A	N/A	N/A	
1933	* 411,291	N/A	N/A***	618,000,000		N/A	N/A	N/A	
1934	* 411,291	N/A	N/A***	618,000,000		N/A	N/A	N/A	
1935	* 411,291	N/A	N/A***	618,000,000		N/A	N/A	N/A	
1936	* 411,291	N/A	N/A***	618,000,000		N/A	N/A	N/A	
1937	* 411,291	N/A	N/A***	618,000,000		N/A	N/A	N/A	
1938	229,579	N/A	595,604	591,810,198		N/A	N/A	N/A	16 Low Pressure Boilers, 2 High Pressure Boilers # 25 & #26 In Service
1939	112,691	N/A	1,777,874	1,042,842,220		N/A	N/A	N/A	First Year of Anthracite Use
1940	333,249	N/A	720,942	864,592,660		N/A	N/A	N/A	
1941	510,465	N/A	333,398	1,086,421,170		N/A	N/A	N/A	
1942	559,515	N/A	47,393	1,012,759,010		N/A	N/A	N/A	
1943	583,796	N/A	144,641	1,027,445,600		N/A	N/A	N/A	
1944	610,409	N/A	247,265	1,153,274,140		N/A	N/A	N/A	
1945	523,550	N/A	194,552	1,006,483,080		N/A	N/A	N/A	Final year anthracite coal was used
1946	455,746	N/A	602,295	1,054,944,330		N/A	N/A	N/A	
1947	388,261	N/A	985,203	1,070,027,750		N/A	N/A	N/A	12 Low Pressure Boilers, 3 High Pressure Boilers in Service.
1948	662,305	N/A	823,729	1,664,765,710		N/A	N/A	N/A	
1949	317,356	N/A	1,741,104	1,476,069,000		N/A	N/A	N/A	
1950	279,059	N/A	1,723,954	1,419,719,720		N/A	N/A	N/A	
1951	260,335	250,289	1,743,567	1,379,931,160		N/A	N/A	N/A	Gas Fuel First Used in Steam Unit
1952	158,562	511,930	2,314,507	1,480,213,800		N/A	N/A	N/A	
1953	5,295	3,785,429	2,143,362	1,306,074,500		N/A	N/A	N/A	
1954	0	2,243,660	1,722,895	983,004,300		N/A	N/A	N/A	
1955	50,650	2,555,817	1,814,343	1,171,606,300		N/A	N/A	N/A	8 Low Pressure Boilers, and 3 High Pressure Boilers, Start of Fluid Coke Use
1956	223,816	1,181,894	1,153,467	1,085,784,600		N/A	N/A	N/A	
1957	147,719	4,674,525	1,158,567	1,221,979,500		N/A	N/A	N/A	End of Fluid Coke Use
1958	85,291	4,304,697	1,009,893	994,544,200		N/A	N/A	N/A	
1959	39,091	3,825,851	1,225,915	947,328,200		N/A	N/A	N/A	
1960	0	2,134,031	1,362,063	806,163,900		N/A	N/A	N/A	

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Table 3.5

## Fuels / Generation Statistics Essex Generating Station

STEAM UNITS					COMBUSTION TURBINES			COMMENTS
YEAR	BITUMINOUS COAL (TON) **	GAS (MCF)	OIL BARRELS	NET GENERATION (Kwh)	GAS (MCF)	OIL BARRELS	NET GENERATION (Kwh)	
1961	20,516	510,554	1,196,329	639,836,500	N/A	N/A	N/A	
1962	7,152	863,043	997,247	533,466,800	N/A	N/A	N/A	
1963	132,731	377,743	549,553	544,409,300	22,492	N/A	1,154,800	No. 8 Combustion Turbine in service
1964	100,223	1,939,694	805,302	694,543,500	138,423	N/A	6,876,200	
1965	113,017	1,364,302	944,179	729,175,300	220,613	N/A	11,564,100	
1966	107,319	2,039,826	1,295,027	896,382,000	217,909	N/A	9,497,000	
1967	87,519	1,914,571	1,891,091	1,090,573,000	217,355	N/A	10,143,000	
1968	0	540,945	2,418,088	985,104,000	491,471	N/A	27,734,000	
1969	0	548,877	3,039,344	1,271,422,000	543,252	N/A	27,178,000	
1970	12,942	277,788	3,082,642	1,169,196,000	590,347	N/A	31,867,000	Last Year of Recorded Solid Fuel Used
1971	0	543,783	2,714,184	1,061,828,000	851,579	382,900	212,131,000	Combustion turbines No. 9,10 & 11 in service
1972	0	0	1,259,773	352,883,000	753,563	1700,412	744,055,000	No. 6 Steam Turbine Unit Retired, No. 12 Combustion Turbine in service
1973	0	0	1,915,936	605,961,000	1,066,374	1472,793	649,563,000	
1974	0	141,290	960,446	370,218,000	191,573	952,438	385,988,000	Steam Units 2,3,4,5&7 Retired
1975	0	175,039	383,814	160,965,000	65,690	88808	31,280,000	
1976	0	119,066	493,268	219,247,000	21,419	241063	92,238,000	
1977	0	417,669	413,466	203,692,000	67,638	499861	195,482,000	
1978	0	0	93,090	45,209,000	27,716	329691	129,029,000	Unit #1 On Inactive Status
1979	0	0	0	0	249,124	223091	101,680,000	
1980	0	0	0	0	3,648,646	243071	338,814,000	
1981	0	0	0	0	3,318,468	77018	247,610,000	
1982	0	0	0	0	1,645,203	58722	125,553,000	
1983	0	0	0	0	2,294,141	97649	187,236,000	
1984	0	0	0	0	1,617,495	63126	130,415,000	Unit #1 Retired
1985	0	0	0	0	1,131,538	38995	86,868,000	
1986	0	0	0	0	1,506,649	51499	114,109,000	
1987	0	0	0	0	4,609,475	14387	331,197,000	
1988	0	0	0	0	4,066,471	50945	312,066,000	
1989	0	0	0	0	4,311,550	63972	325,467,000	
1990	0	0	0	0	4,048,413	1053	308,343,000	
1991	0	0	0	0	3,613,577	1473	282,856,000	
1992	0	0	0	0	2,001,559	9684	161,270,000	
1993	0	0	0	0	2,889,749	16577	231,353,000	
1994	0	0	0	0	2,268,447	44076	189,536,000	
1995	0	0	0	0	3,462,214	13373	278,898,000	
TOTAL					52,170,133	6,736,677	6,319,051,100	

## NOTES

- 1 \* These figures were arrived at by averaging the coal fuel use for the years of 1923 and 1924. Generation was arrived by proportioning generation to coal use for 1924.
- 2 \*\* A Total of 63,596 tons of Anthracite and 39,407 tons of Fluid Coke were also used. This represents less than 1% of the total coal use at Essex since 1915.
- 3 \*\*\* Although some oil was used on the Low Pressure Boilers in the years 1933 - 1937, the quantity has not been identified or estimated.

**Table 3.6****Pennsylvania Bituminous Coal Constituents/Properties**

Typical Properties			
Parameter	Avg.	Min.	Max.
Ash	10.1 %	3.85 %	19.8 %
Carbon	75.9 %	65.8 %	77.95 %
Hydrogen	5.14 %	4.60 %	5.33 %
Moisture	4.46 %	9.0 %	8.38 %
Nitrogen	1.47 %	1.37 %	1.60 %
Oxygen	6.29 %	4.96 %	7.68 %
Sulfur	2.35 %	0.5 %	8.25 %
HHV Btu/lb	13,266	11,756	14,072

**West Virginia Bituminous Coal Constituents/Properties**

Typical Properties			
Parameter	Avg.	Min.	Max.
Ash	9.89 %	6.05 %	15.50 %
Carbon	75.80 %	71.30 %	77.95 %
Hydrogen	5.10 %	4.64 %	6.09 %
Moisture	5.69 %	1.20 %	8.38 %
Nitrogen	1.52 %	1.40 %	1.60 %
Oxygen	6.93 %	4.78 %	9.30 %
Sulfur	1.32 %	0.82 %	1.92 %
HHV Btu/lb	13,256	11,554	14,072

Ref: EPRI PISCES Database

**Table 3.7**

**Bituminous Coals from West Virginia  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Antimony	0.91	0.5	1.42
Arsenic *	13.86	1.82	32.3
Barium *	124	28	270
Beryllium	0.68	0.07	0.9
Cadmium *	0.29 **	0.05	0.6
Chloride *	615	66.2	910
Chromium *	19.88	10	34.9
Copper *	27.35	5.2	160
Fluoride	95.7	53.4	128
Lead *	7.39	2.5	17.37
Mercury *	0.16	0.05	0.41
Nickel *	15.52	8	42
Selenium	3.46	0.9	7.8
Silver	0.27 **	0.05	0.57 **
Sulfur *	13,248	8,200	19,200
Thallium			3.1
Vanadium	39	29	61
Zinc *	30.4 **	2.27 **	62

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.8**

**Bituminous Coals from Pennsylvania  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Mean	Min.	Max.
Antimony	0.76	0.24	1.42
Arsenic *	17.48	1	58.43
Barium *	125.85	24.48	270
Beryllium	0.62	0.07	0.9
Cadmium *	1.03 **	0.03	3.4 **
Chloride *	842.86	740	910
Chromium *	20.77	8.35	34.9
Copper *	52.13 **	30.7 **	160
Fluorine	72.17	56.3	107
Lead *	6.87	1.8	17.11
Mercury *	0.23	0.03	0.85
Nickel *	18.76 **	8	42
Phosphorus *	18.75	4.5	37
Selenium	3.05	1	7.8
Silver	0.44 **	0.01	1.25 **
Sulfur *	23,543	5,000	62,500
Thallium			3.1
Vanadium	32.9	10.9	61
Zinc *	24.22	4.58	46

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

Table 3.9

**Bituminous Coal from Eastern USGS Province  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Acenaphthene	0.01	0.01	0.01
Acenaphthylene	0.15	0.07	0.23
Antimony	1.26 **	0.24	4
Arsenic *	12.68	0.7	131
Barium *	101.95	13	270
Benzo(a)pyrene *	0.09	0.06	0.12
Benzo(g,h,i)perylene	0.16	0.07	0.21
Beryllium	1.1	0.07	2.4
Bis(2-ethylhexyl)phthalate			0.58
Cadmium *	1.52 **	0.03	10.4
Chloride *	854	66.2	5,500
Chromium *	18.31	2	60
Chrysene *	0.18	0.15	0.23
Copper *	27.08 **	5.36	160
Dibenzo(a,h)anthracene *	0.02	0.02	0.02
Fluoranthene	0.1	0.05	0.13
Fluorene *	0.09	0.06	0.12
Lead *	23.47 **	1.8	590
Mercury *	0.21 **	0	1.25
Naphthalene *	2.02	1.6	2.7
Nickel *	18.11 **	5.15	46
Phenanthrene	0.71	0.45	1
Phosphorus *	75.7 **	0.01	234
Pyrene *	0.13	0.07	0.2
Selenium	3.23 **	0.01	14
Silver	0.39 **	0.01	1.25
Sulfur *	19,868	5,000	62,500
Thallium	2.13 **	0.63 **	4.96 **
Vanadium	35.61	5.5	78.5
Zinc *	34.86	2.27	280

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.10**

**No. 6 Fuel Oil  
Typical Properties**

<b>Percent by Weight:</b>	
Sulfur	0.7 - 3.5
Hydrogen	(9.5 to 12.0) *
Carbon	(86.5 to 90.2) *
Ash	0.01 - 0.5
<b>Gravity:</b>	
Degree API	7 to 22
Specific Gravity	1.022 to 0.922
Density (pound/gallon)	8.51 to 7.68
<b>Pour Point, F</b>	+ 15 to + 85
<b>Viscosity Values:</b>	
Centistokes at 100° F	260 to 750
SSF at 122° F	45 to 300
Water and sediment, % by vol	0.05 to 2.0
Heating value, Btu/pound gross	17,410 to 18,990
*Estimated	

API = American Petroleum Institute

SSF = Seconds Saybolt Furol

Ref: Steam-Its Generation and Use, Babcock & Wilcox,  
40th Edition, 1992, page 8-15, Table 13

**Table 3.11**

**No. 6 Fuel Oil  
Hazardous Substances**

<b>Typical Concentration (ppmw)</b>			
<b>Substance</b>	<b>Avg.</b>	<b>Min.</b>	<b>Max.</b>
Antimony	0.23	0.03	0.52
Arsenic *	0.41 **	0.09	2
Barium *	3.87 **	2.53 **	5.87
Beryllium	0.04 **	0.01 **	0.22 **
Cadmium *	0.58 **	0.2 **	3.5 **
Chloride *	145	12	799
Chromium *	0.91 **	0.18	5 **
Copper *	5.55 **	0.01	12.6
Fluoride	7.78	6	12
Lead *	2.71 **	0.1	19.5
Mercury *	0.04 **	0.01	0.1 **
Nickel *	32	11	43.5
Phosphorus *	1.79	0.36	7.73
Selenium	0.28 **	0.05 **	1.1 **
Silver	0.08 **	0.05 **	0.08
Sulfur *	7,854	2,500	57,900
Vanadium	12.5	4	69
Zinc *	0.92	0.03	3.1

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.12**

**Bituminous Bottom Ash from West Virginia Coal  
Hazardous Substances**

<b>Typical Concentration (ppmw)</b>			
<b>Substance</b>	<b>Avg.</b>	<b>Min.</b>	<b>Max.</b>
Antimony	3.99 **	1.6	7
Arsenic *	8.74 **	4	30.9
Barium *	1,086.13	740	1,600
Beryllium	12.57 **	8.48 **	23
Cadmium *			ND - 0.97
Chloride *	16.24	0.55	60
Chromium *	145.07	103	221
Copper *	126.48 **	86.4 **	220 **
Fluoride			ND - 0.19
Lead *	96.58 **	14.8	700
Mercury *	0.01 **	0	0.02
Nickel *	121.68	63.1	252
Phosphorus *			1946
Selenium	64.64 **	0.55	938
Silver	59.43 **	9.7 **	208
Sulfur *	3,521 **	343	16,000
Thallium			ND - 97
Vanadium	211	157	273
Zinc *	127.13 **	23.5	203

ppmw = parts per million by weight

ND - 0.19, 0.97, or 97 = Not Detected by Analytical Method to 0.19, 0.97, or 97 ppm Limit

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Note: Information not available for typical organic hazardous substances for West Virginia coal

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.13**

**Bituminous Fly Ash from West Virginia Coal  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Antimony	6.84 **	1.1	11
Arsenic *	133.8	26.3	308
Barium *	1,060	618	2,200
Beryllium	13.6	8.72	27
Cadmium *	1.05 **	0.1	3.8
Chloride *	104.11	2.5	610
Chromium *	168.34	97.1	259
Copper *	196.47 **	85	532
Fluoride	33.44	1.7	145
Lead *	103.78	8	800
Mercury *	0.25	0	0.88
Nickel *	127.27	6.6	299
Phosphorus *			2551
Selenium	72.05	5.4	1,193
Silver	21.32 **	0.3	187
Sulfur *	10,511 **	1400	66,000
Thallium	91.7 **	25	100 **
Vanadium	280.1	152	560
Zinc *	234.63	16	750

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Note: Information not available for typical organic hazardous substances for West Virginia Bituminous coal

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

Table 3.14

**Bituminous Bottom Ash from Pennsylvania Coal  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
1,2,4,5-Tetrachlorobenzene			ND - 1
1,2,4-Trichlorobenzene			ND - 1
1,3-Dichlorobenzene			ND - 1
1,4 - Dichlorobenzene			ND - 1
1 - Naphthylamine			ND - 1
2,3,4,6-Tetrachlorophenol			ND - 2
2,4,5-Trichlorophenol			ND - 1
2,4,6-Trichlorophenol			ND - 1
2,4-Dichlorophenol			ND - 1
2,4-Dimethylphenol			ND - 1
2,4-Dinitrophenol			ND - 5
2,4-Dinitrotoluene			ND - 1
2,6-Dichlorophenol			ND - 1
2,6-Dinitrotoluene			ND - 1
2-Chloronaphthalene			ND - 1
2-Chlorophenol			ND - 1
2-Naphthylamine			ND - 1
2-Nitrophenol			ND - 1
2-Picoline			ND - 1
3,3-Dichlorobenzidine			ND - 2
3-Methylcholanthrene			ND - 1
4-Bromophenyl phenyl ether			ND - 1
4-Chlorophenyl ether			ND - 1
4-Nitrophenol			ND - 5
Acenaphthene			ND - 1
Acenaphthylene			ND - 1
Acetophenone			ND - 1
Aniline			ND - 1
Anthracene *			ND - 1

ppmw = parts per million by weight

ND - 1, 2 or 5 = Not Detected by Analytical Method to 1, 2 or 5 ppm Limit

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

Table 3.14 (Cont)

Bituminous Bottom Ash from Pennsylvania Coal  
Hazardous Substances

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Antimony	22.12	1.6	69
Arsenic *	7.95	2.8	30.9
Barium *	1,008.4	650	1,600
Benz(a)anthracene *			ND - 1
Benzidine			ND - 1
Benzo(a)pyrene *			ND - 1
Benzo(b)fluoranthene *			ND - 1
Benzo(g,h,i)perylene			ND - 1
Benzo(k)fluoranthene *			ND - 1
Benzoic acid			ND -5
Beryllium	5.12	4.8	5.4
Bis(2-chloroethoxy)methane			ND - 1
Bis(2-chloroethyl)ether			ND - 1
Bis(2-ethylhexyl)phthalate			ND - 1
Cadmium *	1.95	0.49	5
Chloride *	31.29	11.6	60
Chromium *	695.5	84	5820
Chrysene *			ND - 1
Copper *	205.4	19	932
Dibenzo(a,h)anthracene *			ND - 1
Dibenzofuran			ND - 1
Dimethylphenethylamine			ND - 1
Ethyl methanesulfonate			ND - 1
Fluoranthene			ND - 1
Fluorene *			ND - 1
Fluoride	14.33	3.87	32.4
Hexachlorobenzene			ND - 1

ppmw = parts per million by weight

ND - 1, 2 or 5 = Not Detected by Analytical Method to 1, 2 or 5 ppm Limit

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

Table 3.14 (Cont.)

Bituminous Bottom Ash from Pennsylvania Coal  
Hazardous Substances

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Hexachlorobutadiene			ND - 1
Hexachlorocyclopentadiene			ND - 1
Indeno (1,2,3-c,d) pyrene			ND - 1
Isophorone			ND - 1
Lead *	120.87	6.2	1082
Mercury *	0.04	0.02	0.05
N-Nitrosodimethylamine			ND - 1
N-Nitrosodiphenylamine			ND - 1
N-Nitrosopiperidine			ND - 1
Naphthalene *			ND - 1
Nickel *	405.54	58	2,939
Nitrobenzene			ND - 1
Pentachlorobenzene			ND - 1
Pentachloronitrobenzene			ND - 1
Pentachlorophenol			ND - 5
Phenacetin			ND - 1
Phenanthrene			ND - 1
Phenol *			ND - 1
Phosphorus *	1,726.67	1,660	1,780
Pronamide			ND - 1
Pyrene *			ND - 1
Pyridine			ND - 1
Selenium	1.9	0.55	2.9
Silver	5.3	4.9	5.9
Sulfur *	2,719	337	16,000
Thallium	58.83	49	85
Vanadium	210.89	83	537
Zinc *	123.05	35	295
p-Dimethylaminoazobenzene			ND - 1

ppmw = parts per million by weight

ND - 1, 2 or 5 = Not Detected by Analytical Method to 1, 2 or 5 ppm Limit

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.15**

**Bituminous Collected Fly Ash from Pennsylvania  
Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Antimony	28.08 **	4	240
Arsenic *	209.34 **	12	1180
Barium *	1,204.21	0.2	2,200
Beryllium	4.8	0.2	7.91
Cadmium *	1.47 **	0.1	6.9
Chloride *	37.96	6.58	67
Chromium *	214.64	130	500
Copper *	145.7 **	57	327
Fluoride	12.12	1.98	34.9
Lead *	145.73	4.8	1154
Mercury *	0.16 **	0.02	0.7
Nickel *	153.26	66	259
Phosphorus *	2,010	500	2,630
Selenium	22	0.5	70
Silver	12.2 **	4.9 **	24 **
Sulfur *	93,77.5	2000	66,000
Thallium	120.83 **	25	240 **
Vanadium	305.63	60	723
Zinc *	198.1	16	357

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.16**

**Bottom Ash Sluice Water from Western Pennsylvania  
Bituminous Coals  
Hazardous Substances - Metals  
(Concentrations in mg/L)**

<b>Chemical</b>	<b>Concentration Range</b>	<b>Mean</b>
Antimony		<0.1
Arsenic*	0.01 - 0.029	0.023
Barium*	0.25 - 0.54	0.40
Beryllium	0.002 - 0.0032	0.0025
Cadmium*		<0.001
Chromium*	0.01 - 0.033	0.024
Copper *		<0.020
Lead*	0.0048 - 0.0092	0.0073
Manganese	0.04 - 0.16	0.12
Mercury*		<0.0002
Molybdenum	0.066 - 0.077	0.072
Nickel*	0.027 - 0.042	0.035
Selenium		<0.005
Silver		<0.01
Vanadium	0.036 - 0.09	0.068
Zinc	0.02	0.037

\*Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G.

mg/L = milligrams per liter

Note: Metals listed as hazardous substances under CERCLA or in EPA's letter of April 30, 1996 to PSE&G that were detected in bottom ash sluice.

Table 3.17

**Ash Pond Effluent from Western Pennsylvania Coal  
Hazardous Substances  
(Concentrations in mg/L)**

<b>Chemical</b>	<b>Filtered Samples</b>	<b>Unfiltered Samples</b>
Barium*	0.91	0.1
Beryllium	<0.0001	<0.0001
Cadium*	<0.0001	<0.00015
Chromium*	0.0015	0.0025
Copper*	0.0015	0.0015
Nickel*	0.007	0.008
Zinc	0.007	0.015

mg/L = milligrams per liter

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G.

NOTE: Metals listed as hazardous substances under CERCLA or in EPA's letter of April 30, 1996 to PSE&G that were detected in ash pond effluent from Western Pennsylvania Coal.

**Table 3.18**

**Available Information  
Condenser Chemical Cleanings  
(Unit Nos. 1-6)**

<b>Date</b>	<b>Equipment Name</b>	<b>Area Cleaned</b>	<b>Materials Used and Procedure Notes</b>	<b>Discharges</b>
1938 or 1939	No. 4 Condenser	Water Side	The water side of the condenser was cleaned using sodium cyanide and oakite at 180°F for eight to ten hours, with limited circulation.	Spent cleaning solution was discharged to the river via the discharge canal.
6/23/45	No. 1 Condenser	Water Side	The cleaning solution contained approximately 1,296 gallons (gals.) of hydrochloric acid (20°BE) + 110 quarts (qts.) of NEP-22 inhibitor, resulting in a 6% HCl solution.	The solution was drained to the discharge canal.
7/21/45	No. 2 Condenser	Water Side	The cleaning solution contained approximately 980 gallons (gals.) of hydrochloric acid (20°BE) + 100 quarts (qts.) of NEP-22 inhibitor, resulting in a 4.5% HCl solution.	The solution was drained to the discharge canal.
6/28/52	No. 2 Condenser	Water Side	The cleaning solution contained approximately 800 gallons (gals.) of hydrochloric acid (20°BE) + 68 quarts (qts.) of NEP-22 inhibitor, resulting in a 3.7% HCl solution.	The solution was drained to the discharge canal.
2/4/58	No. 2 Condenser	Water Side	The cleaning solution contained 1,376 gallons hydrochloric acid with NEP-22 inhibitor. The solution was drained to the discharge canal and flushed using the circulators, resulting in a 6.4% HCl solution.	The solution was drained to the discharge canal.
6/9/45	No. 3 Condenser	Water Side	The cleaning solution contained approximately 1,200 gallons (gals.) of hydrochloric acid (20°BE) + 120 quarts (qts.) of NEP-22 inhibitor, resulting in a 3.8% HCl solution.	The solution was drained to the discharge canal.
6/3/49	No. 3 Condenser	Water Side	The cleaning solution contained approximately 1,950 gallons (gals.) of hydrochloric acid (20°BE) + 144 quarts (qts.) of NEP-22 inhibitor. Condenser was flushed for 2 hours with circulators, resulting in a 4.6% HCl solution.	The solution was drained to the discharge canal.
5/13/54	No. 3 Condenser	Water Side	The cleaning solution contained approximately 2,000 gallons (gals.) of hydrochloric acid (20°BE) + 152 quarts (qts.) of NEP-22 inhibitor, resulting in a 4.6% HCl solution.	The solution was drained to the discharge canal.

**Table 3.18 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
5/13/54	No. 3 Condenser	Steam Side	The cleaning solution contained approximately 2,000 gals. of hydrochloric acid (20°BE) + 152 qts. of NEP-22 inhibitor. A caustic soda solution was used for a neutralizing flush and rinse.	The solution was drained to the discharge canal.
5/13-14/54*	No. 3 Condenser	Water Side	The cleaning solution contained approximately 1,100 gallons (gals.) of hydrochloric acid (20°BE) + 110 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.5% HCl solution.	The solution was drained to the discharge canal..
7/7/45	No. 4 Condenser	Water Side	The cleaning solution contained approximately 1,768 gallons (gals.) of hydrochloric acid (20°BE) + about 120 quarts (qts.) of NEP-22 inhibitor, resulting in a 4.7% HCl solution.	The solution was drained to the discharge canal.
3/25/49	No. 4 Condenser	Water Side	The cleaning solution contained approximately 1,350 gallons (gals.) of hydrochloric acid (20°BE) + 100 quarts (qts.) of NEP-22 inhibitor. Condenser was flushed for 3/4 of an hour with circulators, resulting in a 3.6% HCl solution.	The solution was drained to the discharge canal.
3/16/50	No. 4 Condenser	Water Side	The cleaning solution contained approximately 1,000 gallons (gals.) of hydrochloric acid (20°BE) + 100 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.7% HCl solution.	The solution was drained to the discharge canal.
4/25/52	No. 4 Condenser	Water Side	The cleaning solution contained approximately 868 gallons (gals.) of hydrochloric acid (20°BE) + 64 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.3% HCl solution.	The solution was drained to the discharge canal.
5/21/55	No. 4 Condenser	Water Side	The cleaning solution contained 1,150 gallons (gals.) of hydrochloric acid (20°BE) + 120 quarts (qts.) of NEP-22 inhibitor, resulting in a 3.0% HCl solution.	The solution was drained to the discharge canal.
3/31/45	No. 5 Condenser	Water Side	The cleaning solution contained approximately 880 gallons (gals.) of hydrochloric acid (20°BE) + 90 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.3% HCl solution.	The solution was drained to the discharge canal.

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**Table 3.18 (Continued)**

<b>Date</b>	<b>Equipment Name</b>	<b>Area Cleaned</b>	<b>Materials Used and Procedure Notes</b>	<b>Discharges</b>
7/20/46	No. 5 Condenser	Water Side	The cleaning solution contained approximately 1,336 gallons (gals.) of hydrochloric acid (20°BE) + 99 quarts (qts.) of NEP-22 inhibitor. Condenser was flushed for ½ hour with circulators, resulting in a 3.5% HCl solution.	The solution was drained to the discharge canal.
4/30/55	No. 5 Condenser	Water Side	The cleaning solution contained approximately 1,357 gallons (gals.) of hydrochloric acid (20°BE) + 150 quarts (qts.) of NEP-22 inhibitor, resulting in a 3.5% HCl solution.	The solution was drained to the discharge canal.
03-19-58	No. 5 Condenser	Water Side	The cleaning solution was approximately 5% hydrochloric acid with 132 quarts (qts.) of NEP-22 inhibitor. The solution was drained to the discharge canal and flushed using the circulators.	The solution was drained to the discharge canal.
5/12/45	Condenser No. 6	Water Side	The cleaning solution contained approximately 1,415 gallons (gals.) of hydrochloric acid (20°BE) + 130 quarts (qts.) of NEP-22 inhibitor, resulting in a 3.6% HCl solution.	The solution was drained to the discharge canal.
4/8/49	Condenser No. 6	Water Side	The cleaning solution contained approximately 1,620 gallons (gals.) of hydrochloric acid (20°BE) + 126 quarts (qts.) of NEP-22 inhibitor, resulting in a 4.1% HCl solution.	The solution was drained to the discharge canal.
4/13/50	Condenser No. 6	Water Side	The cleaning solution contained approximately 1,145 gallons (gals.) of hydrochloric acid (20°BE) + 88 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.9% HCl solution.	The solution was drained to the discharge canal.
9/13/51	Condenser No. 6	Water Side	The cleaning solution contained approximately 1,000 gallons (gals.) of hydrochloric acid (20°BE) + 100 quarts (qts.) of NEP-22 inhibitor, resulting in a 2.5% HCl solution.	The solution was drained to the discharge canal.
7/5/52	Condenser No. 6	Water Side	The cleaning solution contained approximately 800 gallons (gals.) of hydrochloric acid (20°BE) + 54 quarts (qts.) of NEP-22 inhibitor, resulting in a 2% HCl solution.	The solution was drained to the discharge canal.

\*Area cleaned was "steam space" (steam side of condenser tubes).

**Table 3.19**

**High Pressure Units - Operating Parameters**

High Pressure Boilers (Nos. 25 & 26)					
Year Installed	Manufacturer	Pressure (psi)	No. of Boilers	Fuels	
1938	B&W	1,350	2	Coal, Oil	
1947	B&W	1,350	1	Coal, Oil, Gas	
High Pressure Steam Turbine/Generators (Unit No. 7)					
Year Installed	Manufacturer	KW	Type	Volts	Maximum Generator Name Plate Rating (KW)
1938	GE	50,000	Topping	13,200	50,000 KW
1947	GE	105,400	Condensing	13,800	116,300 KW

B&W = Babcock & Wilcox  
 GE = General Electric  
 psi = Pounds Per Square Inch  
 KW = Kilowatts

Table 3.20

**Raw Materials**  
**Unit No. 7, Boilers 25 & 26**  
**1937 - 1974**

Materials	Use and Description	EPA Letter	CERCLA Listed Substance
<b>Fuels</b>			
Bituminous Coal (WVa Primary Source & PA Alternate Source)	Boiler Fuel	*	
No. 6 Fuel Oil	Boiler Fuel	*	
Combustion Air	Boilers and Combustion Turbines		
<b>Fuel Additives or Treatments</b>			
Coal Trol (22% phosphoric acid)	May Have Been Used for Treatment of Coal Piles to Prevent Freezing		*
<b>Boiler Water Treatment Chemicals</b>			
Sodium Sulfite	Boiler Water Treatment Oxygen Scavenger, Used in ppm Dosages		*
Sodium Hydroxide	Boiler Water Treatment and as Neutralizing Agent		*
Anhydrous Disodium Phosphate	Boiler Water Treatment, Phosphate Addition Used in ppm Dosages		*
Anhydrous TriSodium Phosphate	Boiler Water Treatment, Phosphate Addition Used in ppm Dosages		*
<b>Chemicals Used For Equipment Cleanings</b>			
Hydrochloric Acid (a.k.a. Aquakleen)	Boiler Heater Chemical Cleaning, Iron Oxide Removal		*
Dow A-124 Inhibitor	Boiler Chemical Cleaning, Iron Oxide Removal		
CitroSolv Formulation (Ammoniated Citric Acid)	Boiler Chemical Cleaning (one cleaning)		
NEP - 22 Inhibitor	Boiler Chemical Cleanings, Iron Removal		
Vertan 675 (tetra ammonium EDTA)	Boiler Chemical Cleanings, Copper Removal		*
Ammonium Hydroxide (Anhydrous/Aqua Ammonia)	Boiler Chemical, pH Adjustment (Vertan or Citrosolve) Cleanings	*	*
Oakite (Trisodium phosphate)	Feedwater Heaters Cleanings, Oxide Removal		*
Sodium Cyanide	Feedwater Heaters Cleanings, Oxide Removal	*	*
Sodium Nitrite	Boiler Chemical Cleaning		*
Rodine 31A Inhibitor	Boiler Chemical Cleaning		
Sodium Hydroxide (Caustic)	Boiler/Feedwater Heater Chemical Cleaning (neutralization)		*
<b>Water Sources</b>			
Not Applicable - This Unit did not have a condenser			
Newark City Water (potable)	Sanitary Uses, Boiler Makeup Provided From Low Pressure Boiler (s) Condensate		
<b>Non-Contact Cooling Water Treatment Chemicals</b>			
Not Applicable - This Unit did not have a condenser			

**Table 3.21**

**Typical Boiler Units 25 & 26  
High Pressure Boiler Chemistry Limits**

<b>Constituent</b>	<b>Limit or Range</b>
pH	10.5 - 11.0
Silica	2 to 5 ppm maximum
PO <sub>4</sub>	25 to 50 ppm
Total Solids	100 - 150 ppm maximum
Specific Conductivity	350 - 550 umhos/cm

**Table 3.22**  
**Available Information - Boiler Chemical Cleanings**  
**(Boiler Nos. 25 and 26)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
1939 or 1940	Boiler No. 25	Economizer Only	<p>This cleaning was performed on only the economizer section of the boiler and was performed only once for each boiler. The economizer of each boiler was chemically cleaned using a solution of 400-600 grains/gallon of hydrochloric acid along with NEP-22 inhibitor. There were approximately 55 economizer tubes in each boiler. Economizer cleaning was labor intensive and time consuming. Four economizer tubes were cleaned at a time. Hoses were connected to the inlet and outlet end of each tube. Cleaning chemicals (HCl and NEP-22) were placed in a mix tank. Circulation of the cleaning solution through the economizer tubes was from the mixing tank, via pump, through the four inlet hoses, through the economizer tubes, and via four outlet hoses to the mixing tank. It took approximately eight hours to clean each set of four economizer tubes. The water capacity for each economizer was approximately 4,280 gallons.</p> <p>(NOTE: For all subsequent acid cleanings of this boiler, the economizer tubes were left full of condensate, which served as a buffer against backflow of acid into the economizer section. At the conclusion of each chemical cleaning, the economizer section would be flushed out.)</p>	Spent solution drained to the discharge canal to the Passaic River.

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/40	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for 1/2 hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
8/40	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for 1/2 hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

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**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
4/41	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of ≈7.0).	Spent solution drained to the discharge canal to the Passaic River.
7/41	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of ≈7.0).	Spent solution drained to the discharge canal to the Passaic River.

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10/41	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
1/42	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010153

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/42	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
9/42	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010154

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
8/43	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
4/44	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010155

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
11/44	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
12/45	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010156

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10/46	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
3/48	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
4/49	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
5/50	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010158

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
9/51	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
6/53	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010159

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/55	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
12/57	Boiler No. 25	Water Side of Boiler Tubes	No. 25 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010160

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
3/15/72	Boiler No. 25	Water Side of Boiler Tubes	<p>The boiler was cleaned using Vertan 675 (tetra-ammonium ethylenediamine tetra acetic acid), an alkaline copper removal process patented by the Dow Chemical Co. The boiler was filled with the A-124 inhibitor, fired and cooled at a frequency to cause the boiler pressure to oscillate between 50 and 150 psi, thus causing the cleaning solution to naturally circulate in the boiler. Additional chemical was injected when necessary to maintain the required parameters. When iron and Vertan concentrations leveled out, indicating completion of the iron removal phase, the firing ceased and the boiler was cooled to approximately 170°F. Air was then injected into various connections in the lower headers to effect copper removal and passivate the newly cleaned metal surfaces. When copper values leveled out the air injection stopped and the boiler drained to the discharge canal, and then given a rinse with hot (180°F) condensate.</p> <p>Chemical Used: 78,400 lbs of Vertan 675 Metals removed: Iron - 3,664 lbs, Copper - 325 lbs</p>	Spent solution trucked off site.

850010161

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10/28/72	Boiler No. 25	Water Side of Boiler Tubes	<p>The boiler was cleaned by Halliburton Industrial Cleaning Service using the CitroSolv process. The boiler was heated, then filled with a 3% solution of ammoniated citric acid at approximately 200°F, with an average pH of 4.0. When iron concentration and acid concentration leveled out, indicating completion of the iron removal phase, the boiler was allowed to cool to 150°F, for the copper removal and metal passivation stage. Anhydrous ammonia was then added to the recirculating pump suction to raise the pH to 9.0. A sodium nitrite solution was pumped to the boiler. Additional anhydrous ammonia was pumped to the system to raise the pH to 10.0. When the copper concentrations leveled out, the boiler was drained.</p> <p>Chemicals used were: 10,300 lbs citric acid, 300 gals. ammonium hydroxide, 9 gals Rodine 31A inhibitor and 800 lbs sodium nitrite. The solvent averaged 205°F, 3.3 pH and 3.2% citric acid for the iron phase. The copper removal phase averaged a 9.1 pH and 135°F. Approximately 1,130 lbs Fe and 30 lbs Cu were removed.</p>	Spent solution was evaporated in No. 26 Boiler.

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
1939 or 1940	Boiler No. 26	Economizer Only	<p>This cleaning was performed on only the economizer section of the boiler and was performed only once for each boiler. The economizer of each boiler was chemically cleaned using a solution of 400-600 grains/gallon of hydrochloric acid along with NEP-22 inhibitor. There were approximately 55 economizer tubes in each boiler. Economizer cleaning was labor intensive and time consuming. Four economizer tubes were cleaned at a time. Hoses were connected to the inlet and outlet end of each tube. Cleaning chemicals (HCl and NEP-22) were placed in a mix tank. Circulation of the cleaning solution through the economizer tubes was from the mixing tank, via pump, through the four inlet hoses, through the economizer tubes, and via four outlet hoses to the mixing tank. It took approximately eight hours to clean each set of four economizer tubes. The water capacity for each economizer was approximately 4,280 gallons.</p> <p>(NOTE: For all subsequent acid cleanings of this boiler, the economizer tubes were left full of condensate, which served as a buffer against backflow of acid into the economizer section. At the conclusion of each chemical cleaning, the economizer section would be flushed out.)</p>	Spent solution drained to the discharge canal to the Passaic River.

850010163

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
3/40	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
9/40	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010164

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
3/41	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
6/41	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010165

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
8/41	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
3/42	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for 1/2 hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010166

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10/42	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of ≈7.0).	Spent solution drained to the discharge canal to the Passaic River.
2/43	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated though the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of ≈7.0).	Spent solution drained to the discharge canal to the Passaic River.

850010167

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
11/43	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
7/44	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010168

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/45	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
9/45	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010169

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/47	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
4/48	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010170

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
4/50	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
8/52	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010171

**Table 3.22 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
3/54	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
4/56	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for ½ hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010172

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
3/4/58	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for 1/2 hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.
11/8/61	Boiler No. 26	Water Side of Boiler Tubes	No. 26 boiler was cleaned using hydrochloric acid in a range of 1% - 5%, inhibited with NEP-22. Caustic was used as a neutralizing rinse. The boiler sections are filled with hot water and recirculated through the acid cleaning tanks to obtain a temperature of 180°F, to preheat the tube metal to 140°F. Acid and inhibitor were then added to the recirculating water to obtain the planned concentration after 1-2 hours of circulation, the boiler was drained to the discharge canal to the Passaic River. The boiler was then flushed for 1/2 hour with condensate. The boiler was then drained and filled again with hot condensate containing caustic soda. After soaking, or recirculating for approximately 1 hour, the caustic solution was drained to the discharge canal to the Passaic River. The boiler was refilled and drained as many times as needed until it reached a neutral condition (pH of $\approx 7.0$ ).	Spent solution drained to the discharge canal to the Passaic River.

850010173

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
2/9/72	Boiler No. 26	Water Side of Boiler Tubes	<p>The boiler was cleaned using Vertan 675 (tetra-ammonium ethylenediamine tetra acetic acid), an alkaline copper removal process patented by the Dow Chemical Co. The boiler was filled with the A-124 inhibitor, fired and cooled at a frequency to cause the boiler pressure to oscillate between 50 and 150 psi, thus causing the cleaning solution to naturally circulate in the boiler. Additional chemical was injected when necessary to maintain the required parameters. When iron and Vertan concentrations leveled out, indicating completion of the iron removal phase, the firing ceased and the boiler was cooled to approximately 170°F. Air was then injected into various connections in the lower headers to effect copper removal and passivate the newly cleaned metal surfaces. When copper values leveled out the air injection stopped and the boiler drained to the discharge canal, and then given a rinse with hot (180°F) condensate.</p> <p>Chemical Used: 75,264 lbs of Vertan 675 Metals removed: Iron - 4,602 lbs, Copper - 434 lbs</p>	Spent solution was evaporated in No. 25 Boiler.

850010174

Table 3.22 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
12/9/72	Boiler No. 26	Water Side of Boiler Tubes	<p>The boiler was cleaned by Haliburton Industrial Cleaning Service using the Citrosolv process. The boiler was heated, then filled with a 6% solution of ammoniated citric acid at approximately 200°F, with an average pH of 4.0. When iron concentration and acid concentration leveled out, indicating completion of the iron removal phase, the boiler was allowed to cool to 150°F, for the copper removal and metal passivation stage. Anhydrous ammonia was then added to the recirculating pump section to raise the pH to 9.0. A sodium nitrite solution was pumped to the boiler. Additional anhydrous ammonia was pumped to the system to raise the pH to 10.0. When the copper concentrations leveled out, the boiler was drained.</p> <p>Chemicals used were 7,500 lbs citric acid, 300 gals ammonium hydroxide, 9 gals Rodine 31A inhibitor, and 800 lbs sodium nitrite. The solvent averaged 202°F, 3.9 pH and 6% citric acid for the iron removal phase. The copper removal phase averaged a 9.9 pH and 134°F. Approximately 852 lbs Fe and 3 lbs Cu were removed.</p>	Spent solution was evaporated in No. 25 Boiler.
				Rinse water drained to the discharge canal.

850010175

**Table 3.23**  
**Summary of Feedwater Heater Chemical Cleanings**  
**(Boiler Nos. 25 And 26)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
07-02-39	No. 7 Turbine High Pressure Drain Cooler	Water Side	Cleaned heater with inhibited hydrochloric acid neutralized with caustic. Acid (5 gal.), Inhibitor (1 pint), Caustic (3 lbs.)	No records.
12-23-39	No. 7 Turbine Low Pressure Drain Cooler	Water Side	Cleaned drain cooler with Oakite (99 lbs.), Cyanide (21.5 lbs.) and Acid (4.75 gals.) with Inhibitor (1.675 pts.). Volume of system was 300 gallons.	No records.
12-27-39	No. 7 Turbine Low Pressure Heater	Water Side	Cleaned heater with Oakite (60 lbs.), Cyanide (15 lbs.), and Acid (28 gals.) with Inhibitor. Acid neutralized with 5 lbs Caustic. Volume of system was 400 gallons.	No records.
12-30-39	No. 7 Turbine Low Pressure Drain Cooler	Steam Side	Cleaned heater with Oakite (200 lbs.), Cyanide (37.5 lbs.) and Acid (56 gals.) -- initial application. Second application was Oakite (125 lbs.) and Cyanide (75 lbs.). No record of Inhibitor usage. Volume of system was 790 gallons.	No records.
12-31-39	No. 7 Turbine Low Pressure Drain Cooler	Water Side	Cleaned heater with solution from previous cleaning (the second application of oakite-cyanide) and added 12 lbs. Oakite and 7 lbs. Cyanide. Volume of system was 300 gallons.	No records.
01-02-40	No. 7 Turbine Low Pressure Heater	Steam Side	Cleaned heater with Oakite (480 lbs.), Cyanide (95 lbs.) and Acid (135 gals.) with Inhibitor (37 pts.). Second treatment used 443 lbs. Oakite and 265 lbs. Cyanide. Volume of system was 2000 gallons.	No records.
01-17-40	No. 7 Turbine High Pressure Drain Cooler	Water Side	Cleaned heater with Oakite (38 lbs.), Cyanide (8 lbs.) and Acid (13 gals.) with Inhibitor (3.5 pts.). Second application used 33 lbs. Oakite and 19 lbs. Cyanide. Volume was 175 gallons.	No records.
01-18-40	No. 7 Turbine High Pressure Drain Cooler	Steam Side	Cleaned heater with Oakite (87.5 lbs.) and Cyanide (18.75 lbs.) Second application contained acid (28 gallons) and Inhibitor (7 pts.) Acid was neutralized with caustic (3 lbs.) Third application contained Oakite (62.5 lbs.) and Cyanide (37.5 lbs.). Volume of system was 400 gallons.	No records.

850010176

**Table 3.23 (Continued)**

<b>Date</b>	<b>Equipment Name</b>	<b>Area Cleaned</b>	<b>Materials Used and Procedure Notes</b>	<b>Discharges</b>
01-20-40	No. 7 Turbine High Pressure Heater	Water Side	Cleaned heater with Oakite (100 lbs.) and Cyanide (37.5 lbs.). No acid was used for this cleaning and no second Oakite treatment.	No records.
01-21-40	No. 7 Turbine High Pressure Heater	Steam Side	Oakite (750 lbs.) and Cyanide (300 lbs.). No acid used for this cleaning. Volume of system was 2400 gallons.	No records.
02-07-44	No. 7 Turbine High Pressure Heater	Water Side	Cleaned heater with Oakite (112 lbs.) and Cyanide (42 lbs.).	No records.
02-10-44	No. 7 Turbine High Pressure Heater	Steam Side	Cleaned heater with Oakite (720 lbs.) and Cyanide (270 lbs.).	No records.
02-25-53	No. 7 Turbine Low Pressure Heater	Water Side	Cleaned heater with Aquakleen (hydrochloric) Acid (108 gallons) and Inhibitor (8 pts.), recirculating for approximately 3.5 hours at an average temperature of 142°F. System was drained overboard and refilled, adding caustic (3 gallons). System was again drained overboard. Repairs were made. System refilled with the addition of flake caustic (400 lbs.) and recirculated for approximately 2.5 hours at an average temperature of 140°F. Caustic concentration average 3.0%. Heater was drained and flushed. System was refilled and heater was cleaned again with the Aquakleen Acid (67.5 gallons) and Inhibitor (5 pts.), recirculating for about 2 hours at an average temperature of 143°F. Acid concentration average 1.9%. System was drained overboard and flushed with service water.	All chemicals, solutions, etc. were discharged overboard.

850010177

**Table 3.23 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
06-03-53	No. 7 Turbine High Pressure Heater	Water Side	Cleaned heater with a caustic solution (5%) for approximately 2 hours at approximately 158°F. The caustic solution was drained overboard and the heater was refilled, flushed and drained overboard. The next cleaning was done with hydrochloric acid (67.5 gallons) and an Inhibitor (2 ½ pts.), recirculated for 2.5 hours at an average temperature of 133°F. Acid concentration was a little less than 2.0%. Heater and system were drained overboard. System refilled, caustic added, system recirculated and drained. System flushed with clear water.	All chemicals, solutions, rinses were discharged overboard.

850010178

Table 3.24

**Typical HCl  
Boiler Chemical Cleaning  
Drain Water Characteristics**

Analyte	Spent Cleaning Drain	First Rinse Drain
pH	1.5	
<b>Major Metals</b>		
Iron	5900 ppm	0.14 ppm
Copper	320 ppm	0.31 ppm
Nickel	210 ppm	0.03 ppm
Zinc	30 ppm	0.01 ppm
<b>RCRA Metals</b>		
Arsenic	0 ppm	0 ppm
Barium	1 ppm	0.01 ppm
Cadmium	0.18 ppm	0.01 ppm
Chromium	3.5 ppm	0.01 ppm
Lead	1.6 ppm	0.002 ppm
Mercury		
Selenium	0.002 ppm	0.002 ppm
Silver	0.17 ppm	0.01 ppm
<b>Other Components</b>		
Acidity		
Alkalinity		
Aluminum	5 ppm	0.05 ppm
Ammonia		
Antimony	5.6 ppm	0.08 ppm
Beryllium	0.1 ppm	0.001 ppm
Boron	6.2 ppm	0.23 ppm
Calcium	74 ppm	18 ppm
Chloride		
Chromium VI	0.24 ppm	
Cobalt	1.6 ppm	0.006 ppm
COD		
Fluoride		
Magnesium	42 ppm	6.2 ppm
Manganese	31 ppm	0 ppm
Molybdenum	0.72 ppm	0.03 ppm
Nitrate		
Nitrite		
Phosphorous		
Potassium	5 ppm	3.2 ppm
Silicon	22 ppm	6.7 ppm
Sodium	160 ppm	35 ppm
Sulfate		
Thallium	9 ppm	0.09 ppm
TOC		
Vanadium	0.3 ppm	0.01 ppm

Ref: EPRI PISCES Database

Table 3.25

**Raw Materials**  
**Unit No. 1 (1947 - 1978)**

Materials	Use and Description	EPA Letter	CERCLA Listed Substance
<b>Fuels</b>			
Bituminous Coal (WVa Primary Source & PA Alternate Source)	Boiler Fuel	*	
No. 6 Fuel Oil	Boiler Fuel	*	
Natural Gas	Boiler and Combustion Turbine Fuel		
Combustion Air	Boilers and Combustion Turbines		
<b>Fuel Additives or Treatments</b>			
Coal Trol (22% Phosphoric Acid)	May Have Been Used for Treatment of Coal Piles to Prevent Freezing		*
<b>Boiler Water Treatment Chemicals</b>			
Sodium Sulfite	Boiler Water Treatment Oxygen Scavenger		*
Sodium Hydroxide	Neutralizing Agent		*
Anhydrous Disodium Phosphate	Boiler Water Treatment, Phosphate Addition		*
Anhydrous Trisodium Phosphate	Boiler Water Treatment, Phosphate Addition		*
<b>Chemicals Used For Equipment Cleanings</b>			
Sodium Meta-Silicate	Initial Pre-Operational Boiler Chemical Cleaning		
Dow A - 120 Inhibitor	Pre-Operational Boiler Chemical Cleaning, Iron Oxide Removal		
Thiourea	Boiler Chemical Cleanings, Copper Removal		*
Citric Acid	Boiler Chemical Cleanings, Copper Removal		
Hydrochloric Acid	Boiler/Condenser/Heater Chemical Cleanings, Iron Removal		*
NEP - 22 Inhibitor	Inhibitor Used With Hydrochloric Acid		
Caustic Sodium Hydroxide/Caustic (NaOH)	Neutralize Acidic High Chemical Cleanings for Boiler/Condenser/Heaters		*
Ammonium Hydroxide (Aqua Ammonia)	Boiler Chemical Cleaning Bromate Cleanings	*	*
Hydrazine at 100 ppm water solution	Hydrazine Was Used As A Passivating Agent In Some Boiler Chemical Cleaning Procedures		*
Anhydrous Trisodium Phosphate	Pre-Operational Boiler Chemical Cleaning/Heater Cleaning		*
Phosphoric Acid	Boiler Chemical Cleaning		*
Ammonium Carbonate	Boiler Chemical Cleaning		*
Sodium Bromate	Boiler Chemical Cleaning		
Potassium Permanganate	Feedwater Heater Chemical Cleaning		*
Oxalic Acid	Feedwater Heater Chemical Cleaning		
Sodium Carbonate (Soda Ash)	Neutralize Acidic Chemical Cleanings for Boiler/Condenser/Headers		
<b>Water Sources</b>			
River Water	Cooling and Various In-Plant Uses		
Newark City Water (potable)	Sanitary Uses, Boiler Makeup Provided From Low Pressure Boiler (s) Condensate		
<b>Non-Contact Cooling Water Treatment Chemicals</b>			
Chlorine (circa 1933)	Non-Contact Cooling Water Condenser, Biofouling Control		*

**Table 3.26****Natural Gas  
Typical Chemical Composition**

<b>Component</b>	<b>Mole Percentage</b>
Nitrogen	0.67 %
Carbon Dioxide	0.71 %
Methane	95.61 %
Ethane	2.37 %
Propane	0.36 %
Iso-Butane	0.08 %
Normal-Butane	0.08 %
Iso-Pentane	0.02 %
Normal Pentane	0.02 %
Hexanes	0.06 %
Specific Gravity	0.5848
Saturated Btu Per Cubic Foot @ 14.73 psi	1,014
Dry Btu Per Cubic Foot @ 14.73 psi	1,032

**Table 3.27**

**Typical Unit No. 1  
High Pressure Boiler Chemistry Limits**

<b>Constituent</b>	<b>Limit or Range</b>
pH	10.5 - 10.8
Silica	2 - 5 ppm maximum
PO <sub>4</sub>	25 - 50 ppm
Total Solids	100 - 150 ppm maximum
Specific Conductivity	350 - 550 umhos/cm

**Table 3.28**  
**Summary of Boiler Chemical Cleanings**  
**(New Unit No. 1)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
11-15-47	No. 1 Boiler	Water Side of Boiler Tubes (Pre-Operational Cleaning)	<p>The boiler was given an alkaline boil out using the following chemical combination: 2600 ppm trisodium phosphate, 125 ppm caustic soda and 800 ppm sodium meta-silicate. Boiler was fired for approximately 18 hours while blowing down through the various blowdown valves. Drum pressure varied from 21 to 225 psi.</p> <p>The boiler was refilled with hot condensate, including the economizer and superheater, and then drained, leaving the superheater and economizer full.</p> <p>The boiler was acid cleaned with a 3.8% hydrochloric acid solution at 160°F. After soaking for approximately 4 hours, the boiler was then drained to the acid cleaning tanks, where the spent solution was neutralized with caustic soda, before draining.</p> <p>The boiler was then filled with city water and condensate at 150°F, and drained immediately (estimated concentration of 0.15% HCl in the rinse water).</p> <p>A neutralizing solution of city water and condensate with 0.25% NaOH and 0.5% Na<sub>3</sub>PO<sub>4</sub> at 180°F was pumped to the boiler. After a 1 hour soak, the boiler was drained.</p> <p>The boiler was next filled with 190°F condensate and drained to the acid cleaning tanks.</p> <p>Chemicals Used:            910 lbs. trisodium phosphate            280 lbs. sodium metasilicate            44 lbs. flake caustic soda            5,000 gals. inhibited hydrochloric acid            8 1/2 drums liquid caustic soda            4 carboys phosphoric acid*</p>	<p>The boiler was cooled and drained via the discharge canal to the Passaic River.</p> <p>The neutralized solution was drained via the discharge canal to the Passaic River.</p> <p>The city water rinse was drained via the discharge canal to the Passaic River.</p> <p>The neutralizing solution was drained via the discharge canal to the Passaic River.</p> <p>No record.</p>

850010183

**Table 3.28 (Continued)**

<b>Date</b>	<b>Equipment Name</b>	<b>Area Cleaned</b>	<b>Materials Used and Procedure Notes</b>	<b>Discharges</b>
02-01-49	Boiler No. 1	Water Side	Chemicals Used: 55 1/2 carboys of hydrochloric acid* 55 1/2 quarts of NEP-22 inhibitor 9 drums of liquid caustic No other information available.	No record.
06-07-51	Boiler No. 1	Water Side	Chemicals used: 60 carboys of hydrochloric acid* 60 quarts of NEP-22 inhibitor 51 gals. (approx.) of liquid caustic No other information available.	No record.
10-02-52	Boiler No. 1	Water Side	Chemicals used: 1,000 gals. (approx.) of hydrochloric acid (via tank truck) 23 gals. of NEP-22 inhibitor 26 gals. of liquid caustic No other information available.	No record.
11-07-53	Boiler No. 1	Water Side	Chemicals used: 1,400 gals. of hydrochloric acid (via tank truck) 27 gals. (approx.) of NEP-22 inhibitor 27 gals. (approx.) of liquid caustic No other information available.	No record.

850010184

Table 3.28 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
07-09-56	Boiler No. 1	Water Side	<p>Chemicals used:  5,011 gals. of hydrochloric acid  100 gals. of NEP-22 inhibitor  108 gals. of liquid caustic</p> <p>Boiler was cleaned with a 5% solution of hydrochloric acid at 140°F, containing 100 gals. of NEP-22 inhibitor. The solution was in the boiler for 3 hrs. 15 mins. before being drained. A condensate rinse followed the draining of the spent solution. A neutralizing rinse, containing 108 gals. of liquid caustic followed the condensate rinse. Following the draining of the neutralizing rinse, the boiler was given a final condensate rinse. Rinses were heated to 180°F before being pumped to the boiler.</p>	The acid solution, rinse waters, neutralizing solution and any excess chemical solutions were all drained to the discharge canal to the Passaic River..
05-58	Boiler No. 1	Water Side	<p>Boiler was cleaned with a 5% solution of inhibited hydrochloric acid. Inhibitor used was NEP-22. Temperature of solution was in the range of 140-150°F. Neutralization done with caustic soda solution. No other information available.</p>	No record.

850010185

Table 3.28 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10-03-65	Boiler No. 1	Water Side	<p>The boiler was cleaned in two stages.</p> <p>First Stage: Copper removal using ammonium bromate at 180°F. Solution contact time was 6 hrs. Two rinses with city water at 180°F completed this phase.</p> <p>Second Stage: Iron and copper removal using 7.5% hydrochloric acid, 3.0% thiourea and 0.3% A120 inhibitor at 150°F. The solution contact time was 6 hrs. The solution was drained under a nitrogen blanket. The boiler was filled with condensate at 150°F for the <u>first rinse</u>, and was drained under nitrogen. The boiler was filled again with condensate containing 0.5% citric acid and 100 ppm hydrazine for the <u>second</u> rinse, and drained under nitrogen. The boiler was filled again with 150°F condensate containing 100 ppm hydrazine, and 0.5% citric acid for the <u>third</u> rinse, and drained under nitrogen. The boiler was then filled with a neutralizing solution containing 0.5% trisodium phosphate and 100 ppm hydrazine at 150°F. The boiler was fired to 75 psig pressure for 6 hrs. The boiler was blown down and finally drained when chemistry requirements were met.</p>	<p><u>All</u> drains from the boiler went to the south ash lake.</p> <p>Uninhibited hydrochloric acid was injected into the bromate drain to reduce the bromate to bromide.</p>

Table 3.28 (Continued)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
10-03-65 (cont'd)	Boiler No. 1	Water Side	<p>Chemicals used in First Stage:</p> <p>3,250 gals. aqua ammonia  4,900 lbs. ammonium carbonate  2,700 lbs. sodium bromate  6,000 gals. 28% hydrochloric acid (used for neutralizing bromate).</p> <p>Chemicals used in Second Stage:</p> <p>9,850 gals. 28% hydrochloric acid  120 gals. A120 inhibitor  10,100 lbs. thiourea  450 lbs. hydrazine  1,800 lbs. trisodium phosphate  700 lbs. citric acid  3,750 gals. sodium hydroxide  7 gals. antifoam agent</p> <p>Metal removed:</p> <p>7,874 lbs. iron (as Fe)  2,693 lbs. copper (as Cu)</p>	

850010187

**Table 3.28 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
12-08-73	Boiler No. 1	Water Side	<p>The boiler was cleaned with a 6% solution of hydrochloric acid, containing 2.0% thiourea (for copper removal), and 0.3% inhibitor. The boiler water side volume was 40,000 gallons. The solution temperature was 140-150°F, and contact time was approximately 6.5 hrs. The boiler was drained under nitrogen to trucks for off site disposal. The boiler was filled with hot condensate and drained under nitrogen, to the chemical waste basin. The boiler was refilled again with hot condensate containing 0.1% citric acid and drained under nitrogen, to the chemical waste basin. The boiler was refilled again with hot (180-190°F) condensate containing 0.5% caustic for neutralization. After soaking for approximately 2 hrs., the boiler was drained to the chemical waste basin. The boiler was filled again with hot (180°F) condensate and drained to the chemical waste basin.</p> <p>Metals removed (approx.):  3,000 lbs. iron (as Fe)  500 lbs. copper (as Cu).</p>	<p>The spent solution was drained to trucks for off site disposal.</p> <p>All other boiler condensate solution were drained to the chemical waste basin.</p>

\* A carboy contains 13 1/2 gallons.

850010188

**Table 3.29**  
**Summary of Condenser Chemical Cleanings**  
**(New Unit No. 1)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
7/25/53	No. 1 Condenser	Water Side	Cleaned with a solution containing approximately 1,680 gallons of hydrochloric acid and 132 quarts of NEP-22, resulting in a 3.5% HCl solution. Spent solution drained. Condenser flushed with fresh water.	Spent solution drained to the discharge canal to the Passaic River.
11/10/53	No. 1 Condenser	Water Side	Cleaned with approximately a 2.5% hydrochloric acid inhibited with 128 quarts of NEP 22. Liquid caustic used for neutralization. Temperature was 110°F-115°F. Circulation method used. No other data available.	Spent solution drained to the discharge canal to the Passaic River.
4/16/55	No. 1 Condenser	Water Side	Cleaned with 2.0% hydrochloric acid inhibited with NEP 22. Liquid caustic used for neutralization. Temperature was 120°F. Circulation method used. No other data available.	Spent solution drained to the discharge canal to the Passaic River.
7/11/56	No. 1 Condenser	Water Side	Cleaning solution contained approximately 1,200 gallons of 20° Baume hydrochloric acid and 124 quarts of NEP-22, resulting in a 2.5% HCl solution. Liquid caustic was used for neutralization. Temperature was 122°F-125°F. Circulation method was used.	Spent solution drained to the discharge canal to the Passaic River.
5/14/58	No. 1 Condenser	Water Side	Cleaning solution contained approximately 1,524 gallons of 20° Baume hydrochloric acid, inhibited with 55 gallons of NEP-22, resulting in a 3.2% HCl solution. Liquid caustic was used for neutralization. Temperature was 104°F-124°F. Circulation method was used. No other data available	Spent solution drained to the discharge canal to the Passaic River.

**Table 3.29 (Continued)**

<b>Date</b>	<b>Equipment Name</b>	<b>Area Cleaned</b>	<b>Materials Used and Procedure Notes</b>	<b>Discharges</b>
12/21/58	No. 1 Condenser	Water Side	Cleaning solution contained approximately 2,000 gallons of 20° Baume hydrochloric acid inhibited with 40 gallons of NEP-22, resulting in a 4.2% HCl solution. Liquid caustic was used for neutralization. Temperature was 128°F-136°F. Circulation method used. No other data available.	Spent solution drained to the discharge canal to the Passaic River.
1/1/60	No. 1 Condenser	Water Side	Cleaned with 3% inhibited hydrochloric acid. Soak method used. No other data available.	No records.
6/21/68	No. 1 Condenser	Water Side	Condenser and two condensate coolers foam cleaned with 4,400 gallons of 28% hydrochloric acid containing 32 gallons of A-120 inhibitor. Anti-foam (12 gallons) was used to collapse the foam when it reached the outlet water boxes. No other data available.	Solution drained to the north ash lake.
12/1/73	No. 1 Condenser	Water Side	Foam cleaned with hydrochloric acid (10%). No other information available.	No records.

Table 3.30

Summary of Feedwater Heater Chemical Cleanings  
(New Unit No. 1)

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
01-01-60	No. 1 Unit Heaters 15 through 18	Steam and Water Sides	Cleaned both steam and water sides with 3% hydrochloric acid and NEP-22. Neutralized with caustic. Rinsed with condensate. Did three acid stages with same acid mix on feedwater side only. Used a total of 100 gal. caustic and 1,580 gal. acid.	All solutions went to discharge canal to the Passaic River.
07-26-69	No. 1 Unit Heaters 15 and 16	Steam and Water Sides	Cleaned with 8% solution of trisodium phosphate and 0.03% wetting agent, at 240°F.	No records.
01-03-70	No. 1 Unit Heaters 15 through 18	Water Side	Cleaned with 5% caustic +2% potassium permanganate at 200°F, followed by a city water rinse. Second stage was 7 1/2% hydrochloric acid +.2% A120 inhibitor plus .25% oxalic acid, followed by a city water rinse, followed by a flush until effluent was same pH and conductivity as city water. Third stage was 3% soda ash, which was drained hot to ash pit. Approximately 105 lbs of iron, 7 lbs of manganese, and .4 lbs of copper were removed.	All solutions went to discharge canal to the Passaic River.
08-23-73	No. 1 Unit Heaters 15 through 18	Steam and Water Sides	First stage: Cleaned with 3% caustic +2% potassium permanganate for 6 hours at 180°F. Solution recirculated.	None. Drained to truck for off site disposal.
			Flushed with hot water. Initial portion went to disposal truck, remainder to waste basin.	Remainder of flush water to chemical waste basin for settling and subsequent discharge from standpipe.
			Flushed again with city water.	Flush water to chemical waste basin.
			Second stage: Cleaned with 15% hydrochloric acid +.3% A120 inhibitor for 6 hours at 165°F. Solution recirculated.	None. Pumped to truck for off site disposal.
			Flushed with city water.	Flush water to chemical waste basin.
			Third stage: A repeat of first stage.	None. Drained to truck for off site disposal.
			Flushes after third stage.	Flush water to chemical waste basin.

850010191

**Table 3.30 (Continued)**

Date	Equipment Name	Area Cleaned	Materials Used and Procedure Notes	Discharges
08-23-73 (Continued)	No. 1 Unit Heaters 15 through 18	Steam and Water Sides	Fourth stage: A repeat of second stage plus acid fill and soak of steam side of heaters with same formulation.	None. Pumped to truck for off site disposal.
			Heaters flushed on water and steam sides.	Flush water to chemical waste basin.
			Fifth stage: Neutralization with 3% soda ash on water and steam sides. Water side recirculated. Steam side just soaked.	Neutralization solution drained and flushed to chemical waste basin.
			Metals removed: 120 lbs iron (Fe); 160 lbs copper (Cu).	
			Water side volume = 1,500 gallons Steam side volume = 6,000 gallons	

**Table 3.31**

**Combustion Turbine Units - Operating Parameters**

<b>Combustion Turbine ID</b>	<b>Year Installed</b>	<b>Fuel Used</b>	<b>Voltage</b>	<b>Phase</b>	<b>Frequency</b>	<b>Name Plate KW Rating</b>	<b>No. Of Units In Plant</b>	<b>Plant Capacity Maximum Generator Name Plate Rating</b>
No. 8 Gas Turbine*	1963	Natural Gas	13,800	3	60	30,000	1	30,000
No. 9 Gas Turbine**	1971	Natural Gas and Distilled Fuel	13,800	3	60	53,133	1	53,133
No. 10 Gas Turbine	1971	Natural Gas and Distilled Fuel	13,800	3	60	167,400	1	167,400
No. 11 Gas Turbine	1971	Natural Gas and Distilled Fuel	13,800	3	60	167,400	1	167,400
No. 12 Gas Turbine	1972	Natural Gas and Distilled Fuel	13,800	3	60	167,400	1	167,400
New No. 9 Gas Turbine	1990	Natural Gas and Distilled Fuel	13,800	3	60	90,000	1	90,000

\* Retired

\*\* Replaced

**Table 3.32**

**Low Sulfur Distillate Fuel Oil  
Typical Characteristics**

<b>Percents by Weight:</b>	
Sulfur	0.05 to 1.0
Hydrogen	11.8 to 13.9
Carbon	86.1 to 88.2
Nitrogen	nil to 0.1
<b>Gravity Values:</b>	
Degrees API	28 to 40
Specific Gravity	0.887 to 0.825
Density (pound/gallon)	7.39 to 6.87
<b>Pour Point, deg. F</b>	
	0 to - 40
<b>Viscosity Values:</b>	
Centistokes at 100°F	1.9 to 3.0
SSF at 122°F	---
<b>Water and sediment, % by vol</b>	
	0 to 0.1
<b>Heating value, Btu/pound gross</b>	
	19,170 to 19,750

API = American Petroleum Institute

SSF = Seconds Saybolt Furol

Ref: Steam-Its Generation and Use, Babcock & Wilcox, 40th Edition, 1992,  
page 8-15, Table 13

**Table 3.33**  
**Kerosene**  
**Typical Characteristics**

<b>Percentages by Weight:</b>	
Sulfur	0.01 to 0.5
Hydrogen	13.3 to 14.1
Carbon	85.9 to 86.7
Nitrogen	nil to 0.1
<b>Gravity Values:</b>	
Degrees API	40 to 44
Specific Gravity	0.825 to 0.806
Density (pounds/gallon)	6.87 to 6.71
<b>Pour Point, deg. F</b>	0 to -50
<b>Viscosity Values:</b>	
Centistokes at 100°F	1.4 to 2.2
SSF at 122°F	----
Water and sediment, % by vol.	----
Heating value, Btu/pound gross	19,670 to 19,860

API = American Petroleum Institute

SSF = Seconds Saybolt Furol

Ref: Steam-Its Generation and Use, Babcock & Wilcox, 40th Editions, 1992,  
page 8-15, Table 13

**Table 3.34**

**Low Sulfur Distillate Fuel Oil  
Metallic Hazardous Substances**

Typical Concentration (ppmw)			
Substance	Avg.	Min.	Max.
Arsenic *			ND - 0.25
Beryllium			ND - 0.05
Cadmium *			ND - 0.05
Chloride *			ND - 30
Chromium *	0.05 **	0.05 **	0.06
Copper *	0.2 **	0.1 **	0.5
Lead *	0.34 **	0.25 **	0.5
Mercury *			ND - 0.1
Nickel *	0.06 **	0.05 **	0.08
Selenium			ND - 0.25
Sulfur *	550	500	600
Zinc	0.15	0.06	0.26

ppmw = parts per million by weight

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

ND - 0.25, 0.1, or 30 = Not Detected by Analytical Method to 0.25, 0.1 or 30 ppm Limit

Ref: EPRI PISCES Database

Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are, or in the case of Average include, Non-Detect data reported at the detection level of the analytical method(s) used.

**Table 3.35**  
**Kerosene**  
**Hazardous Substances**

Typical Concentration		
Substance	Ref 1 (mg/L)	Ref 2 (mg/kg)
3-Methylcholanthrene	< 0.1 , <0.08	
7,12 - Dimethylbenz(a)anthracene	--, 17.0	
Acenaphthene	40, 51	
Acenaphthylene	25, 38 **	
Anthracene *	< 2.0 , 7.3	0.04
Benz(a)anthracene *	< 0.75 , < 0.09	< 0.01
Benzo(a)pyrene *	< 0.50 , < 0.30	< 0.01
Benzo(b)fluoranthene *	< 0.75 , < 0.20	
Benzo(ghi)perylene	< 2.0 , <0.30	
Benzo(k)fluoranthene *	< 0.50 , < 0.04	
Chrysene *	< 2.0 , <0.11	U
Dibenz(a,h)anthracene *	< 0.75 , <0.50	
Fluoranthene	< 4.0 , 1.0	0.09
Fluorene *	< 2.0 , 36	
Indeno(1,2,3-c,d)pyrene	< 2.0 , <0.30	
Naphthalene *	1,286 , 2,000	
Phenanthrene	1.9 , 493	U
Pyrene *	< 2.0 , 2.0	0.16

mg = milligrams

kg = kilograms

L = Liter

Ref 1 - Goodman & Harbison 1980

Ref 2 - Guerin, 1978

\* Chemicals cited in USEPA's letter of April 30, 1996 to PSE&G

\*\*Range and mean values reported

U = Undetected

Table 3.36

**Raw Materials  
Combustion Turbines  
1963 - Present**

Material	Use and Description	EPA Letter	CERCLA Listed Substance
<b>Fuels</b>			
Natural Gas	Combustion Turbine Fuel		
No. 2 Distillate Oil	Combustion Turbine Fuel	*	
Kerosene	Combustion Turbine Fuel	*	
Combustion Air	Combustion Turbines		
<b>Fuel Additives or Treatments</b>			
DGT - 2 Smoke Suppressant (Barium & Manganese based)	Combustion Turbine Fuel Additives		*
GTA - 19 Smoke Suppressant (Cerium based)	Combustion Turbine Fuel Additives		
<b>Boiler Water Treatment Chemicals</b>			
Penetone 19 <sup>(1)</sup>			
<b>Chemicals Used For Equipment Cleanings</b>			
Not Applicable			
<b>Water Sources</b>			
Newark City Water (potable)	Makeup to Closed Loop Cooling		
<b>Chemicals Used for Cooling System (Unit No. 8 and New Unit No. 9 Only)</b>			
Ethylene Glycol	Closed Loop Cooling Water System	*	*
Corrosion Inhibitor (unspecified)	Closed Loop Cooling Water System		
<b>Non-Contact Cooling Water Treatment Chemicals</b>			
Not Applicable			

<sup>(1)</sup> Contains hexylene glycol (13.0%), which is not on the CERCLA hazardous substances list. Other constituents of Penetone-19 are not identified.

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container' Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
No. 1 Tank	Steel Tank (ES)	S.E. Corner Yard	No. 6 Fuel Oil	20,000 bbls	Earthen Dike	Removed From Service
No. 2 Tank	Steel Tank (ES)	S.E. Corner Yard	No. 6 Fuel Oil	100,000 bbls	Steel Dike	Use Changed - 1990
No. 2 Tank	Steel Tank (ES)	S. E. Corner Yard	DM Water	100,000 bbls	Steel Dike	
No. 11 Station Power Transf.	Steel Housing (P)	N. Boiler House	Transil Oil	1,675 gal	Concrete Dike	Removed From Service
No. 5 Station Power Transf.	Steel Housing (P)	E. Boiler House	Transil Oil	1,955 gal	Concrete Dike	Removed From Service
No. 6 Station Power Transf.	Steel Housing (P)	E. Boiler House	Transil Oil	1,955 gal	Concrete Dike	Removed From Service
House Heating Boiler Tank	Steel Tank (ES)	W. Side Switch House	No. 2 Fuel Oil	8,000 gal	Concrete Dike	Removed From Service
Gasoline Tank	Fiberglass Tank (UST)	S.E. No. 1 Drive House	Gasoline	1,000 gal	None	Removed From Service
Diesel Tank (2)	Steel Tank (UST)	S.E. No. 1 Drive House	Diesel Oil	3,000 gal 1,000 gal	None	Removed From Service
Hazardous Waste Drum Storage Area	Steel Drums (ES)	S. Unit No. 12	Waste Oil	55 gal Drums = 15 Drums	Concrete Dike With Roof	
C-1355 Reactor	Steel Housing (P)	138KV Yard	Dielectric Fluid (Transil Oil)	5,725 gal	Housekeeping (Crushed Stone)	
H-1308 Reactor	Steel Housing (P)	138KV Yard	Dielectric Fluid	5,725 gal	Housekeeping	
W-1323 Reactor	Steel Housing (P)	138KV Yard	Transil Oil	5,725 gal	Housekeeping	Removed From Service
No. 132-1 Phase 1	Steel Housing (P)	138KV Yard	Transil Oil	13,700 gal	Housekeeping	Replaced
No. 132-1 Phase 2	Steel Housing (P)	138KV Yard	Transil Oil	13,700 gal	Housekeeping	Replaced
No. 132-1 Phase 3	Steel Housing (P)	138KV Yard	Transil Oil	13,700 gal	Housekeeping	Replaced
No. 132-1 Phase 1	Steel Housing (P)	138KV Yard	Dielectric Fluid	4,595 gal	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
No. 132-1 Phase 2	Steel Housing (P)	138KV Yard	Dielectric Fluid	4,595 gal	Housekeeping	
No. 132-1 Phase 3	Steel Housing (P)	138KV Yard	Dielectric Fluid	4,595 gal	Housekeeping	
Oilostatic Tank	Steel Tank (P)	Oil Pump House	Dielectric Fluid	20,000 gal	Deversion/Concrete Dike	
Pump House	Steel Housing (P)	Pump House	Dielectric Fluid	N/A	Deversion/Concrete Dike	
Oilostatic Tank (P)	Steel Tank (P)	Next to Pump House	Dielectric Fluid	10,000 gal	Covered Concrete	
Oilostatic Tanks (2)	Steel Tank (P)	Oil Pump House	Dielectric Fluid	12,000 gal (6,000 gal/ea)	Deversion/Concrete Dike	
No. 8 Main Transf.	Steel Housing (P)	S. No. 8 Unit	Transil Oil	3,800 gal	Concrete Dike	Removed From Service
Old No. 9 Main Transf.	Steel Housing (P)	N. No. 9 Unit	Transil Oil	3,560 gal	Concrete Dike	Removed From Service
Old No. 9 Unit Gen. Lube Oil Reservoir	Steel Tank (P)	No. 9 Unit Generator	Lube Oil	3,300 gal		
Old No. 9 Unit Chemical Additive Tank	Steel Tank (ES)	N. No. 9 Unit	DGT-2M	1,000 gal	Concrete Dike	Removed From Service
Old No. 9 Unit Fuel Oil Drain Tank	Steel Tank (UST)	N.W. Corner No. 9 Unit	No. 2 Fuel Oil	275 gal		Removed From Service
Old Unit No. 9 OCB (3)	Steel Tank (P)	N. Side of Unit No. 9	Oil	183 gal (91 gal/ea)	Housekeeping	Removed From Service
Drum Storage Area	Steel Drums (ES)	W. Unit No. 10	Various Drums	55 gal Drums (47)	Concrete Dike	
Unit No. 10 Fuel Oil Reclaim Sumps (2)	Steel Tank (P)	S. Unit No. 10	Kerosene	100 gal (55gal/ea)	Concrete Vault	
No. 10 Unit Fuel Oil Drain Tank (4)	Steel Tank (UST)	N. & S. Corner No. 10 Unit	No. 2 Fuel Oil	250 gal/ea 1,000 gal		Removed From Service
Tank No. 3	Steel Tank Installed With Leak Detection (ES)	S.E. Corner Yard	Kerosene	5,040,000 gal	Earthen Dike and Claymax Liner	
No. 220-1 Transformer	Steel Housing (P)	230KV Yard	Dielectric Fluid (Transil Oil)	22,000 gal	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container' Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
No. 220-2 Transformer	Steel Housing (P)	230KV Yard	Dielectric Fluid (Transil Oil)	18,000 gal (17,010 gal?)	Housekeeping	
No. 26-2A Transformer	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,380 gal	Housekeeping	
No. 26-2B Transformer	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,380 gal	Housekeeping	
No. 26-1A Phase 3	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
No. 26-1A Phase 2	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
No. 26-1A Phase 1	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
No. 26-1B Phase 3	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
No. 26-1B Phase 2	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
No. 26-1B Phase 1	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	2,145 gal	Housekeeping	
Transil Oil Tanks (5)	Steel Tank (ES)	13KV Yard	Transil Oil	30,675 gal	Housekeeping	Removed From Service
No. 132-3 Tap Changer	Steel Housing (P)	13KV Yard	Transil Oil	4,350 gal	Housekeeping	Removed From Service
No. 132-3 Phase 3	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	
No. 132-3 Phase 2	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	
No. 132-3 Phase 1	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	
No. 132-2 Tap Changer	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	3,960 gal	Housekeeping	
No. 132-2 Phase 2	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
No. 132-2 Phase 3	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	
No. 132-2 Phase 1	Steel Housing (P)	13KV Yard	Dielectric Fluid (Transil Oil)	7,430 gal	Housekeeping	
No. 132-4 Transformer	Steel Housing (P)	N. Unit No. 10	Dielectric Fluid	9,500 gal	Housekeeping	
Unit No. 10 Generator Lube Oil Reservoir (4)	Steel Tank (P)	Unit No. 10 Generator	Lube Oil	400 gal (100 gal/ea)	Building	
No. 11 Main Transformer	Steel Housing (P)	N. No. 11 Unit	Transil Oil	11,440 gal	Housekeeping	
No. 11 Unit Fuel Oil Drain Tank (8)	Steel Tank (UST)	N. & S. Corner No. 11 Unit	No. 2 Fuel Oil	275 gal/ea (2,200 gal)		Removed From Service
No. 11 Main Transformer	Steel Housing (P)	N. Unit No. 11	Dielectric Fluid	3,900 gal	Housekeeping	
Unit No. 11 Fuel Oil Reclaim Tank (2)	Steel Tank (P)	Unit No. 11	Kerosene	950 gal (475 gal/ea)	Concrete Vault	Removed From Service
Unit No. 11 Generator Lube Reservoir (4)	Steel Tank (P)	Unit No. 11 Generator	Lube Oil	1,000 gal (250 gal/ea)	Building	
Chemical Additive Tank	Steel Tank (ES)	S. Unit Nos. 10 & 11	DGT-2M	2,500 gal	Concrete Pad & Dike	
No. 12 Main Transformer	Steel Housing (P)	N. No. 12 Unit	Transil Oil	14,130 gal	Housekeeping	Removed From Service
No. 12 Unit Fuel Oil Drain Tank (8)	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal/ea (2,200 gal)		
Lube Oil Storage	Steel Drums	W. No. 12 Unit	Multigear B, Gulfcrest 44, Turbo Oil, 2380, Fryquel 220, Harmony 43AW, Aturbrio 71	55 gal drums		
No. 12 Main Transformer	Steel Housing (P)	N. Unit No. 12	Dielectric Fluid	8,900 gal	Housekeeping	
Unit No. 12 Fuel Oil Reclaim Tank (2)	Steel Tank (P)	S. Unit No. 12	Kerosene	950 gal (475 gal/ea)	Concrete Vault	Removed From Service
Unit No. 12 Generator Lube Oil Reservoir (4)	Steel Tank (P)	Unit No. 12 Generator	Lube Oil	1,000 gal (250 gal/ea)	Building	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37  
ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Chemical Additive Tank	Steel Tank (ES)	S. Unit No. 12	DGT-2M	1,000 gal	Concrete Pad & Dike	
No. 9 Main Transformer	Steel Housing (P)	Unit No. 9	Dielectric Fluid	11,007 gal	Concrete Pad clay pit with Sump	
Unit No. 9 Generator Lube Oil Reservoir	Steel Tank (P)	Unit No. 9 Generator	Lube Oil	3,300 gal	Diversionory Collection System	
26KV Tie Bus O-U Reactors (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	1,100 gal	Housekeeping	
Group "U" OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	315 gal (105 gal/ea)	Housekeeping	
C-289, N-248 OCB (2)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	530 gal (265 gal/ea)	Housekeeping	
Plank Rd Reactors Phase's 1-3(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	1,071 gal (357 gal/ea)	Housekeeping	
V-48 Plank Rd OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
No. 9 Generator Transformer OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	330 gal (110 gal/ea)	Housekeeping	
L-12 Ironbound Reactor Phase 1-3 (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	1,071 gal (357 gal/ea)	Housekeeping	
L-12 Ironbound OCB (3) Transformer	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
26-2 Trans. Group "U" OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	315 gal (105 gal/ea)	Housekeeping	
Group "U" Secondary PT (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	15 gal (5 gal/ea)	Housekeeping	
No. 8 Station Power (Now No. 13)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	240 gal	Housekeeping	
26KV Transformer Bus OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	318 gal (106 gal/ea)	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container' Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Group O-U Trans Bus Reactors (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	1,071 gal (357 gal/ea)	Housekeeping	
26KV 132-4 Primary PT (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	12 gal (4 gal/ea)	Housekeeping	
26KV Group "0" OCB	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	105 gal/ea	Housekeeping	
0327 Reactor & J556	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	265 gal/ea	Housekeeping	
H-86 Plank Rd Reactor (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	720 gal (240 gal/ea)	Housekeeping	
H-86 OCB's (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
G-163 Reactor	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	265 gal	Housekeeping	
D-368 Ironbound Reactors (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	971 gal (357 gal/ea)	Housekeeping	
D-368 OCB's (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
I-87 Plank Rd Reactor (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	1,071 gal (357 gal/ea)	Housekeeping	
I-87 OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
132-4 26KV Group "0" OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	315 gal (105 gal/ea)	Housekeeping	
No. 12 Station Power	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	240 gal	Housekeeping	
I-85 Harrison OCB (3) (Now 4-25)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
X-102 A&B OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	411 gal (137 gal/ea)	Housekeeping	
T-358 Clay Street OCB (3) (Now M-21)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	318 gal (106 gal/ea)	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Z-52 Harrison OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	411 gal (137 gal/ea)	Housekeeping	
26KV Group M OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
132-1 Transformer Group M OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
132-1 Transformer 26KV PTS (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	45 gal (15 gal/ea)	Housekeeping	
26KV Transformer Bus I-M OCB	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	125 gal/ea	Housekeeping	
Transformer Bus I-M Synch Transformer	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	5 gal	Housekeeping	
P-94 Harrison OCB (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	375 gal (125 gal/ea)	Housekeeping	
J-556 Path OCB (3) (Now G-163)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	318 gal (106 gal/ea)	Housekeeping	
S-357 A&B Reactor	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	265 gal	Housekeeping	
H-346 Clay St OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	318 gal (106 gal/ea)	Housekeeping	
26KV Tie Bus Group "I" OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
132-1 Transformer 26KV Group I OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
26KV Neutral Resistor Shunt OCB	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	100 gal (approx)	Housekeeping	
26-1 Transformer 26KV OCB(3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	315 gal (105 gal/ea)	Housekeeping	
26KV Tie Bus Group I-M Reactors (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	3,300 gal (1,100 gal/ea)	Housekeeping	
26-1 Pot Transformer (3)	Steel Housing (P)	26KV Switchyard	Dielectric Fluid	45 gal (15 gal/ea)	Housekeeping	Removed From Service

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Potential Transformer	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	15 gal (approx)	Housekeeping	
C-1355 & 132-4 B&R OCB (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	3,510 gal (1,170 gal/ea)	Housekeeping	
220-1, 138KV Breaker (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,550 gal (850 gal/ea)	Housekeeping	
132-1 Transformer 132KV OCB(3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	3,510 gal (1,170 gal/ea)	Housekeeping	
132KV Main Bus Sec 3-4 (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,550 gal (850 gal/ea)	Housekeeping	
H-1308 & No 11 Main Transformer 138KV Breaker (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,475 gal (825 gal/ea)	Housekeeping	
132-2 Transformer 132KV OCB (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,550 gal (850 gal/ea)	Housekeeping	
132KV Sec 2, Bus Tie OCB (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,550 gal (850 gal/ea)	Housekeeping	
220-2, 138 KV OCB (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	3,510 gal (1,170 gal/ea)	Housekeeping	
132-3, 132KV OCB(3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	3,420 gal (1,140 gal/ea)	Housekeeping	
132KV Main Bus Sec 1-30 OCB (3)	Steel Housing (P)	132KV Switchyard	Dielectric Fluid	2,550 gal (850 gal/ea)	Housekeeping	
No. 8 Lighting Transformer	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	20 gal (approx)	Housekeeping	
No. 7 Lighting Transformer	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	20 gal (approx)	Housekeeping	
OCB's (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
G319 City Dock 13KV OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
V337 City Dock 13KV OCB (3) (Now Y-337)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
H320 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
L324 13KV OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
132-3 Transformer 13KV Group "O" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
26-1 Transformer 13KV Group "O" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
13KV Neutral Ground Transformer 13KV Group "O" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
13KV Tie Bus Group "O" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	
13KV Tie Bus Group "U" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	
13KV Bus Group "U" PT (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	45 gal (15 gal/ea)	Housekeeping	
13KV Neutral Ground Trans 13KV Group "U" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	
13KV Neutral Ground Transformer	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	1.013 gal	Housekeeping	
26-1 Transformer PTS (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	57 gal (19 gal/ea)	Housekeeping	
Group O-U PT's (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	30 gal (10 gal/ea)	Housekeeping	
26-1 Transformer 13KV Group "U" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	390 gal (130 gal/ea)	Housekeeping	
132-3 Transformer 13KV Group "U" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	342 gal (114 gal/ea)	Housekeeping	
No. 5 Stat Power Transformer OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
V-256 OCB(3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
D-82 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	177 gal (59 gal/ea)	Housekeeping	
D-316 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
X-388 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	156 gal (52 gal/ea)	Housekeeping	
No. 5 & 6 Lighting Transformer (2)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	42 gal (21 gal/ea)	Housekeeping	
13KV Groups "O" and "6" Shunt (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	459 gal (153 gal/ea)	Housekeeping	
No. 11 Station Power Transformer OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
H-164 OCB(3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
L-376 Penna 13KV OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
S-461 13KV OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
No. 1 Station Power Transformer OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
132-3 Transformer Group "R" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	342 gal (114 gal/ea)	Housekeeping	
No. 5 Generator Group "R" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	Not In Service
No. 2 Generator Group "R" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	Not In Service
13KV Tie Bus Group "R" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
13KV Tie Bus Group "X" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	
No. 2 Generator 13KV Group "X" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	342 gal (114 gal/ea)	Housekeeping	Not In Service
No. 5 Generator 13KV Group "X" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	345 gal (115 gal/ea)	Housekeeping	Not In Service
132-3 Transformer 13KV Group "X" OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	342 gal (114 gal/ea)	Housekeeping	
L-38 Miller St OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
T-332 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
E-473 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
Z-442 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	174 gal (58 gal/ea)	Housekeeping	
S-487 OCB (3)	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	243 gal (81 gal/ea)	Housekeeping	
No 26-1 Spare Transformer	Steel Housing (P)	13KV Substation	Dielectric Fluid	2,145 gal	Housekeeping	
No 26-1 Transformer A&B Blower Motor	Steel Housing (P)	13KV Substation	Dielectric Fluid	35 gal (5 gal/ea)	Housekeeping	
Allis-Chalmers 45KVA Unit	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	7,000 gal	Housekeeping	
No 132-3 Spare Transformer	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	7,430 gal	Housekeeping	
No. 7 Pole Transformer	Steel Housing (P)	13KV Switchyard	Dielectric Fluid	80 gal (20 gal/ea)	Housekeeping	
Oilstatic 26 2A&2B Tank	Steel Tank (P)	Transformer Repair Building	Dielectric Fluid	470 gal	Building	
No. 12 Station Power Transformer	Steel Housing (P)	West of Switchgear Building	Dielectric Fluid	155 gal	Housekeeping	

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container/ Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Battery Station 60 Cells	Glass Containers (P)	26 Control House	Sulfuric Acid	150 gal (2.5 gal/ea)	Building	
Kerosene Piping	Steel Pipe (P)	Above & Below Ground	Kerosene	N/A	Below Ground Steel Pipe	
Unit No. 10 Nelson Winslow Filters (2)	Steel Housing (P)	S. Unit No. 10	Fuel Oil	400 gal (approx)	Concrete Dike	
Unit No. 10 Lube Oil Reservoirs (16)	Steel Housing (P)	Inside Unit No. 10	Lube Oil	480 gal 30 gal/ea	Building	
Drum Storage Area	55 gal Drum (IS)	Unit No. 10 Maintenance Area	Lube Oil Waste Oil	55 gal (approx)	Building	
Unit No. 11 Nelson Winslow Filter (6)	Steel Housing (P)	S. Unit No. 11	Kerosene	2,400 gal (400 gal/ea)	Concrete Dike	
Unit No. 11 Lube Oil Reservoirs (24)	Steel Housing (P)	Inside Unit No. 11	Lube Oil	720 gal (30 gal/ea)	Building	
Unit No. 12 Lube Oil Reservoirs	Steel Housing (P)	Inside Unit No. 12	Lube Oil	30 gal/ea	Building	
Unit No. 12 Nelson Winslow Filters (4)	Steel Housing (P)	S. Unit No. 12	Kerosene	1,600 gal (400 gal/ea)	Concrete Dike	
Unit No. 12 Natural Gas Distillate	Steel Housing (P)	S. Unit No. 12	Water & Oil	10 gal (approx)	Concrete Dike	
Fuel Oil Forwarding Pumps & Valves	Steel Valves (P)	W. Side Tank No. 3 Dike	Kerosene	N/A	Concrete Dike	
Unit No. 9 4KV Cranking Transformer	Steel Housing (P)	S.W. Corner Unit No. 9	Dielectric Fluid	250 gal (approx)	Housekeeping	
Unit No. 9 480V Aux Transformer	Steel Housing (P)	S.W. Corner Unit No. 9	Dielectric Fluid	250 gal (approx)	Housekeeping	
Unit No. 9 Lube Oil Surge Tank	Steel Housing (P)	Unit No. 9	Lube Oil	100 gal (approx)	Building	
Unit No. 9 Vacuum Demister Pot	Steel Housing (P)	N. Unit No. 9	Waste Oil	40 gal (approx)	Building	
Unit No. 15 Station Power Transformer	Steel Housing (P)	230KV Switchyard	Dielectric Fluid	70 gal (approx)	Housekeeping	
Unit No. 14 Station Power Transformer	Steel Housing (P)	230KV Switchyard	Dielectric Fluid	70 gal (approx)	Housekeeping	Removed From Service

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST - Underground Storage Tank

**TABLE 3.37  
ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Nelson Winslow Filters (2)	Steel Housing (P)	Tank No. 3 Unloading Area	Kerosene	800 gal (400 gal/ea)	Concrete Dike	
Battery Station (60 Batteries)	Glass Containers (P)	230KV Yard Central Building	Sulfuric Acid	300 gal (5 gal/ea)	Building	
Battery Station (100 Batteries)	Glass Containers (P)	Unit No. 10 Control Room	Sulfuric Acid	500 gal (5 gal/ea)	None	
Drum Storage Area	55 gal Drums (IS)	Maintenance Shop	Lube Oil	600 gal	Building	
Lube Oil Storage Sheds (5)	55 gal Drums (P)	Near Each Generator Unit	Lube Oil	8 Drums	Hazmat Storage Shed	
Group "A" Tie Bus OCB (3)	Steel Housing (P)	Switch House, 6th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
Group "M" Tie Bus OCB (3)	Steel Housing (P)	Switch House, 6th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
Group "I" Tie Bus OCB (3)	Steel Housing (P)	Switch House, 6th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
Group "B" Tie Bus OCB (3)	Steel Housing (P)	Switch House, 6th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
Group "B" Tie No. 7 Generator OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
Group "A" Tie No. 7 Generator OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
132-2 Trans. Group "B" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
132-2 Trans. Group "A" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
No. 4 Generator Group "I" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
No. 4 Generator Group "M" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service

<sup>1</sup>Tank Codes: P = Process; ES = Exterior Storage; IS = Interior Storage; UST = Underground Storage Tank

**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
26-2 Trans. 13KV Group "I" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
26-2 Trans. 13KV Group "M" OCB (3)	Steel Housing (P)	Switch House, 2nd Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
8001-Sec 1 13KV Network OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
LP-324 Essex Transmission OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
X-492 Substation OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
No. 1 Station Power 13KV OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
Q-69 Long-Naien OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
8003-Sec 1 13KV Network Group "A" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
8001-Sec 1 13KV Network OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
J-88 P.V.J.C. FPEG Y-103 Naval Shipyard OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
M-325 Essex Yard Transmission OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
No. 2 Station Power Trans. 13KV OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
P-562 BKR OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
8003- Sec 1 13 KV Group "B" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
13 KV Group "A" & "B" Reactor Shunt Group "B" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service

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**TABLE 3.37**  
**ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
13 KV Group "A" & "B" Reactor Shunt Group "A" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
No. 3 Generator Group "I" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
No. 3 Generator Group "M" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	600 gal (200 gal/ea)	Building	Not In Service
LP-432- Sec 1 Group "I" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
No. 6 Station Power Trans. 13 KV OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
LP-432- Sec 1 Group "m" OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
O-41 Washington Ave OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
E-473 Western Ave OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
No. 3 Station Power Trans. 13KV OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
R-96 Washington Ave OCB (3)	Steel Housing (P)	Switch House, 4th Floor	Dielectric Fluid	300 gal (100 gal/ea)	Building	Not In Service
Battery Station (240 Batteries)	Glass Containers (P)	Switch Building	Sulfuric Acid	3,600 gal (15 gal/ea)	Building	
Drum Storage Area	55 gal Drum (IS)	Transformer Building	Lube Oil	55 gal	Overpack Drum	
Air Compressor	Steel Housing (P)	Transformer Building	Lube Oil	20 gal	Building	
Unit No. 11 (4) Battery Station (60 Cells)	Glass Containers (P)	Unit No. 11	Sulfuric Acid	1,500 gal (25 gal/ea)	None	
Unit No. 12 (4) Battery Station (60 Cells)	Glass Containers (P)	Unit No. 12	Sulfuric Acid	1,500 gal (25 gal/ea)	None	
Unit No. 10 OCB's (3)	Steel Housing (P)	N. Unit No. 10	Dielectric Fluid	336 gal (112 gal/ea)	Housekeeping	

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**TABLE 3.37  
ESSEX GENERATING STATION STORAGE & PROCESS EQUIPMENT**

<i>Designation</i>	<i>Container<sup>1</sup> Type</i>	<i>Location</i>	<i>Product Type</i>	<i>Product Quantity</i>	<i>Containment/Diversion Type</i>	<i>Current Status</i>
Paint Storage	Steel Containers (P)	Trailer West of Maintenance	Paint	100 gal (Approx.) (5 gal/ea)	Building	
Battery Station Old Unit No. 9 (60 Batteries)	Glass Containers (P)	Old Unit No. 9	Sulfuric Acid	360 gal (6 gal/ea)	None	Removed From Service
Battery Station Unit No. 9 (56 cells)	Glass Containers (P)	Unit No. 9	Sulfuric Acid	168 gal (3 gal/ea)	Building	
Nos. 3 and 4 Transformers	Steel (P)	N. Side of Transformer Repair House	Dielectric Fluid	128 gal/ea	Operator in Attendance	
10-12 Reclaim Oil Tank	Steel Tank	West of No. 13 Fuel Oil	Fuel Oil	8,000 gal	Earthen Dike & Claymax Liner	
Diesel Storage Tank	Steel Tank	N. Of Heliport	Diesel Fuel	500 gal	Concrete Dike & Curbing	
Unit No. 11 Fuel Oil Reclaim Tank (2)	Steel Tank (P)	Unit No. 11	Kerosene	(2) 55 gal Temporary Holding Tanks	Concrete Vault	
Unit No. 12 Fuel Oil Reclaim Tank (2)	Steel Tank (P)	S. Unit No. 12	Kerosene	(2) 55 gal Temporary Holding Tanks	Concrete Vault	
Unit No. 10 Natural Gas Distillate	Steel Housing (P)	S. Unit No. 10	Distillate	10 gal (approx.)	Drip Pan	
Unit No. 11 Natural Gas Distillate	Steel Housing (P)	S. Unit No. 11	Water & Oil	10 gal (approx.)	Drip Pan	
Unit No. 9 Suction Strainers (2)	Steel Housing (P)	E. of Unit No. 9	Kerosene	N/A	Concrete Dike & Roof	
Unit No. 9 Fuel Oil Forwarding Pumps (2) and Heater (1)	Steel Housing (P)	E. of Unit No. 9	Kerosene	N/A	Small Building within Containment	
Unit No. 9 Fuel Oil Filters (2)	Steel Housing (P)	E. of Unit No. 9 in Small Building	Kerosene	N/A.	Concrete Dike & Roof	
Maintenance Shop Satellite Accumulation Area	55 gal Drums (IS)	N. of Maintenance Shop	Waste Oil Spent Solvents	110 gal (55 gal/ea)	Storage Shed	
Stormwater Frack Tank (Portable)	Steel (ES)	W. of No. 3 Fuel Oil Tank	Stormwater Residual Oil	20,000 gal	Operator in Attendance	

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**Table 3.38**

**Lubricating Oils  
Hazardous Substances**

<b>TYPICAL CONCENTRATION (ppmw)</b>		
<b>Substance</b>	<b>Ref 1</b>	<b>Ref 2</b>
Anthracene*	9.9	0.13
Benzo(a)anthracene*	0.68	0.34
Benzo(a)pyrene*	0.23	0.03
Benzo(ghi)perylene	0.85	0.07
Benzo(a)fluoranthene*	0.62	0.41
Chrysene*	3.2	1.26
Fluoranthene	2.0	0.70
Fluorene*	11.7	
Phenanthrene	46.5	7.09
Pyrene*	2.5	1.83

ppmw = parts per million by weight

Ref 1 - Neff et al., 1994

Ref 2 - Grimmer al., 1981

\*Chemicals cited in USEPA's letter of April 1996 to PSE&G

Table 3.39

**Essex Generating Station  
Underground Storage Tanks  
(All Have Been Removed)**

Designation & No. of Tanks	Container Type	Location	Type	Size	Date of Installation
No. 9 Unit Fuel Oil Drain Tank	Steel Tank	N.W. Corner No. 9 Unit	No. 2 Fuel Oil	275 gal	1971
No. 10 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 10 Unit	No. 2 Fuel Oil	250 gal	1971
No. 10 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 10 Unit	No. 2 Fuel Oil	250 gal	1971
No. 10 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 10 Unit	No. 2 Fuel Oil	250 gal	1971
No. 10 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 10 Unit	No. 2 Fuel Oil	250 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 11 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. No. 11 Unit	No. 2 Fuel Oil	275 gal	1971
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972

**Table 3.39 (Continued)**

<b>Designation &amp; No. of Tanks</b>	<b>Container Type</b>	<b>Location</b>	<b>Type</b>	<b>Size</b>	<b>Date of Installation</b>
No. 12 Unit Fuel Oil Drain Tank	Steel Tank	N. & S. Corner No. 12 Unit	No. 2 Fuel Oil	275 gal	1972
Gasoline Tank	Fiberglass Tank	S.E. No. 1 Drive House	Gasoline	1,000 gal	Unknown
Diesel Tank	Steel Tank	S.E. No. 1 Drive House	Diesel Oil	3,000 gal	1952
Diesel Tank	Steel Tank	S.E. No. 1 Drive House	Diesel Oil	1,000 gal	Unknown
Coal Equipment Lube Oil Tank	Steel Tank	Coal Unloading Tower	Lube Oil	Unknown	Unknown

**Table 3.40**  
**Summary of ACOE Dredging Along Passaic River**

<b>DREDGING DATES</b>	<b>DEPTH (FEET)</b>	<b>AREA/REACH</b>	<b>QUANTITY (CUBIC YARDS)</b>
4/17 - 5/19	16	Jackson St. to Clay Street	185,178
5/21 - 6/21	20	Bay to Jackson Street	102,732
2/21 - 7/22	20	From 7,600' to 8,500' above Penn RR Bridge	62,805
6/21/22 - 6/22/22	20	From 1,000' above Lincoln Hwy Bridge 7,600' above Penn RR Bridge	515,500
10/22 - 2/23	20	From 8,500' above Penn RR Bridge to Jackson St. Upper 800' was new work	159,176
9/26	10	At Belleville (6-foot depth)	2,666
7/28	10	At Belleville (6-foot depth)	3,908
4/30 - 6/30	10	At Belleville	36,658
6/30 - 10/30	10	At Belleville	55,597
7/30 - 8/30	10	Above Rutherford Avenue Bridge	35,042
8/30 - 6/31	10	Belleville Bar to 8th St. Bridge	567,357
1/31 - 6/31	10	Above Rutherford Avenue Bridge	39,382
7/31 - 11/31	10	Above Rutherford Avenue Bridge	65,856
7/31 - 12/31	30	Entire Stretch	1,430,706
7/31 - 2/32	10	Belleville Bar to 8th Street Bridge Upper Level	589,110

**Table 3.40 (Continued)**

<b>DREDGING DATES</b>	<b>DEPTH (FEET)</b>	<b>AREA/REACH</b>	<b>QUANTITY (CUBIC YARDS)</b>
7/31 - 10/32	10	Scattered rock shoals	30,550
3/32 - 4/32	10	Passaic River	8,735
6/32	10	Scattered rock shoals	3,202
9/32 - 11/32	16	Vicinity Congoleum Mfg. Co. to Erie R.R. Bridge (Montclair & Greenwood Lake Div)	228,344
10/32 - 6/33	30	Junction to 3,000' above Lincoln Hwy Bridge	607,212
12/32	10	At DL & W R.R. Bridge	Not Documented
8/33	16	At Erie RR Bridge (Montclair & Greenwood Lake Div)	Not Documented
9/33 - 11/33	10	Belleville Bar	30,051
6/36 - 10/36	20	Lower end of Jackson St. Bridge	800,860
10/6/37 - 10/28/37	10	Vic. Montclair & Greenwood Lake RR Bridge	32,553
5/39 - 6/39	10	Passaic R. Mouth of Second River, Belleville, NJ & bet. Union Avenue Bridge Rutherford & 2nd St. Br. Passaic, NJ	3,173
7/39 - 10/39	10	Passaic R. Mouth of Second River, Belleville, NJ & bet. Union Avenue Bridge Rutherford & 2nd St. Br. Passaic, NJ	51,815
7/40 - 4/41	30	Junction to 3,000' above Lincoln Hwy Bridge (Part of Contract with Newark Bay - Main Channel & Hackensack River)	1,202,000

**Table 3.40 (Continued)**

<b>DREDGING DATES</b>	<b>DEPTH (FEET)</b>	<b>AREA/REACH</b>	<b>QUANTITY (CUBIC YARDS)</b>
11/44 - 5/45	10	Opposite Second River	25,632
2/46 - 6/46	30	Junction to 3,000' above Lincoln Hwy Bridge (Part of Contract with Newark Bay - Main Channel & Hackensack River)	934,507
12/46	--	Obstruction Passaic R.	--
5/49 - 6/49	16	Penn RR Freight Bridge & Center St. Bridge	272,753
7/49 - 8/49	16	Penn RR Freight Bridge & Center St. Bridge	97,074
9/49 - 4/50	16	Center St. Bridge to Naim Linoleum Works	344,739
1/50 - 4/50	10	Gregory at 8th St. Bridge	153,501
5/50 - 6/50	--	Miscellaneous Shoals	--
1/51 - 3/51	30	Junction to CRR of NJ Bridge	329,225
4/53 - 6/53	30	Junction to 500' north of Junction (Part of Contract with Newark Bay Main Channel & Hackensack River)	10,000
10/56 - 12/56	10	Vic 2nd River	37,234
1/57 - 4/57	30	CRR of NJ Bridge to 2,000' upstream	130,657
1/57 - 6/57	30	Junction to CRR of NJ Bridge	283,284
11/61 - 4/62	30	Junction to CRR of NJ Bridge (Part of contract with Hackensack River)	245,000
2/65 - 6/65	30	Junction to Lincoln Hwy Bridge	505,535

Table 3.40 (Continued)

DREDGING DATES	DEPTH (FEET)	AREA/REACH	QUANTITY (CUBIC YARDS)
5/20/71 - 7/2/71	30	Junction to 1,000' South of CRR of NJ Bridge	155,556
12/71 - 3/72	30	From Newark Bay to Lincoln Highway Bridge	74,551
1/74 - 2/74	10	Vic 2nd River	64,970
3/76 - 7/76	20	(Location Not Specified)	191,621
5/77 - 7/77	30	From Jct. to Kearny Pt. Reach (CNJ Br.)	477,988
5/77 - 9/88	30	From Jct. to Kearny Pt. Reach (CNJ Br.)	477,988
9/2/81 - 10/7/81	--	(Removal of Wrecks and Associated Debris from Passaic River)	N/A
7/14/83 - 9/23/83	30	Junction to Lincoln Bridge	540,000
1983	30	From Newark Bay to Lincoln Highway Bridge	540,000

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TABLE 3.41

**CHARACTERISTICS OF TRANSIL OILS SUPPLIED BY  
VARIOUS EQUIPMENT MANUFACTURERS<sup>(a)</sup>  
(FROM PUBLISHED DATA)**

Characteristic	Pennsylvania Transformer Division	Westinghouse (Wemco C)	Allis-Chalmers (No. 3)	Genl. Electric (10C)	Pacific Elec. Mfg. Co.
Flash Point (Cleveland Open Cup Method)	270F (132C) Minimum	135C Min.	132C Min.	130C Min.	135C Min.
Fire Point (Cleveland Open Cup Method)	155C at 300F Minimum	152C Min. at 350F	149C at 300F (Min.)	145C Min.	150C Min.
Viscosity (Standard Saybolt Test at 37.8C) OC	60 Seconds	60 Sec. Max. 280 Sec. Max.	63 Sec. Max.	58 Sec. Max.	60 Sec. Max.
Specific Gravity (at 15.5C)	.90 to .910	.898	.91 at 15.6C	.865-.900	.884
Pour Point	-40F (-40C)	-45.6C Max.	-40C Max.	-40C Max.	-40C Max.
Snyder Life Test for Sludge	18 to 22 days		---		
Dielectric Strength (1" circular discs 0.1" apart)	26,000V Min.	26,000V Min. (on shipment)	26,000V Min. (on shipment)	26,000V Min. (on shipment)	26,000V Min
Neutralization No. (Mg.koh per gram of oil)	.05 Maximum	.03 Maximum	.03 Maximum	.02 Maximum	.03 Maximum
Steam Emulsion No. (sec.)	25	25 Maximum	25 Maximum		9 Maximum
Color:(A) N.P.A. Designation Cream White (B) Tag Robinson	No. 1-1/2 No. 17-1/2	2.0 Maximum		ASTM-1 Max.	
Coefficient of Expansion per deg.C	.0007	.000725			
Free and Corrosive Sulphur Mineral Acids (Chloride & Sul.)	Nil Nil	Nil	Nil	Nil	Nil
Weight/gal.		7.5 lbs.			7.5 lbs.
Dielectric Constant		2.2			
Interfacial tension (dynes/sq. cm)		40 Min.			
Specific heat		.488 Approx.			
Precipitation No.		0			

(a) Source: Insulating Oil Report-  
Report on Insulating Oil Purchase, Storage, Handling, Testing, Treatment  
August 12, 1996and Transportation (12/62) - PSE&G

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TABLE 3.42

**SWITCHING AND GENERATING STATION  
STORAGE TANKS-OIL ANALYSIS<sup>(a)</sup>**

	Gallons in Tank	NN	IFT	PPM	KV	PF (40°C)	Date Tested
#1 Dirty OCB	2,560	.10	24.0	54	18.0	.37	08/25/61
#3 Dirty OCB	3,470	.12	23.3	57	23.6	.20	08/25/61
#4 Clean Transformer	---	.26	22.0	48	33.6	.72	08/25/61
#5 Dirty Transformer	6,200	.16	23.9	75	16.5	.63	08/25/61

(a) Source: Insulating Oil Report -  
Report on Insulating Oil Purchase, Storage, Handling, Testing, Treatment  
And Transportation (December 1962)

Notes: NN = neutralization number (mg.koh/gram oil)  
IFT = interfacial tension (dynes/sq. cm.)  
PPM = parts per million of water  
KV = kilovolts of dielectric strength  
PF = power factor



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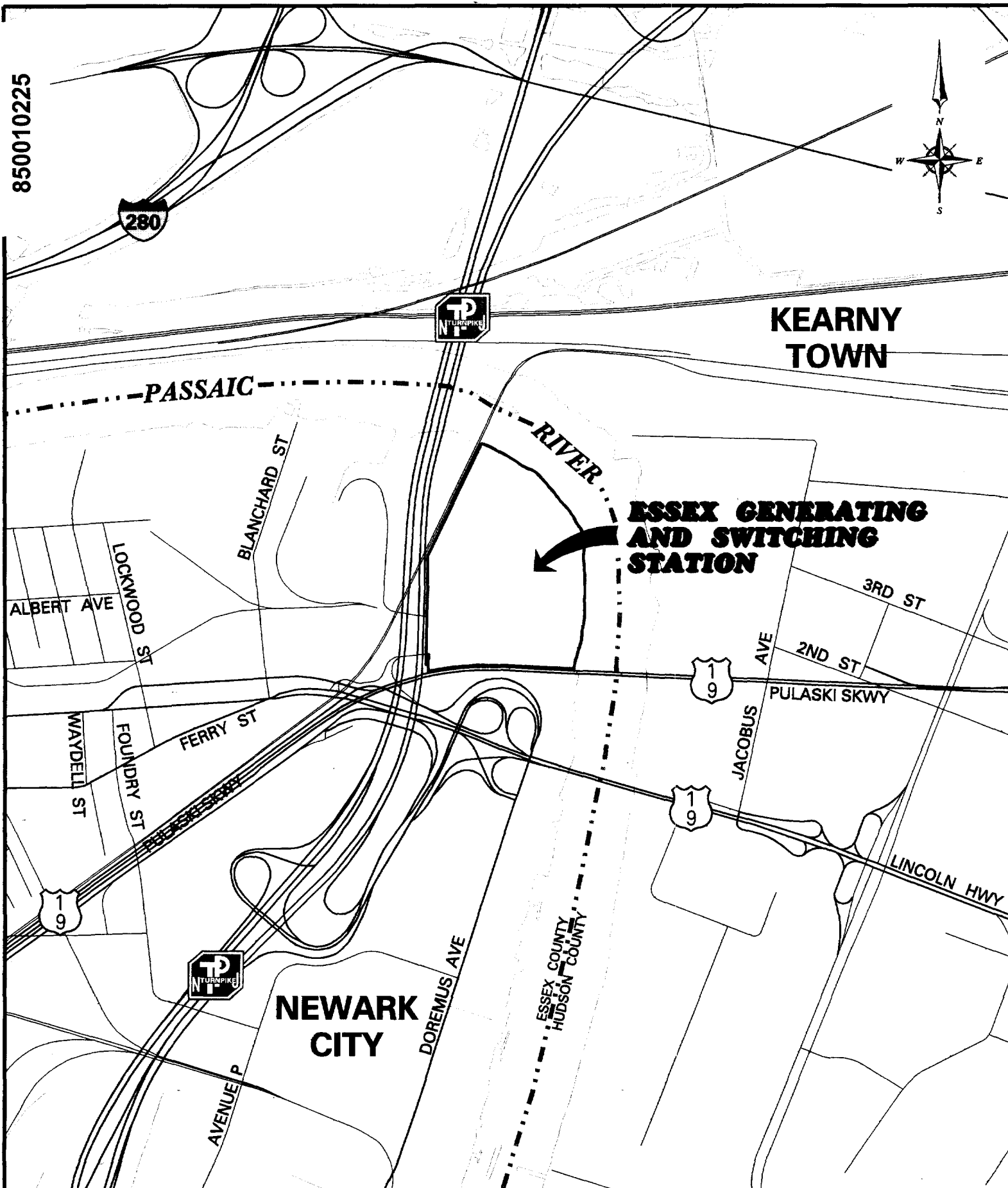


Figure 2.1

FROM U.S.C.&G.S. JERSEY CITY QUADRANGLE

DATA MEETS NMAS FOR 1"=200' MAPPING

NOT-TO-SCALE

NAD-27


# ESSEX GENERATING AND SWITCHING STATION

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

OWNERSHIP TRANSACTION  
MAP  
"ESSEX GENERATING & SWITCHING STATION"  
MAP OF PROPERTY  
SITUATED IN THE  
CITY OF NEWARK ESSEX COUNTY, N.J.  
SCALE 1" = 160' AUG. 8, 1989


850010226

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

NO	DATE	DESCRIPTION	DWN	CKD
REVISION				
		<b>PSEG</b> Public Service Electric & Gas Company		
SURVEYS & MAPPING				
<b>ESSEX GENERATING AND SWITCHING STATION</b>				
CITY OF NEWARK			ESSEX CO, N.J.	
<b><i>EPA RESPONSE</i></b>				
CADD	NO	DATE	JULY 30, 1996	SCALE 1" = 100'
FILE		CHECKED		EXAMINED


850010227

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

NO	DATE	DESCRIPTION	DWN	CKD
REVISION				
		<b>PSEG</b> Public Service Electric & Gas Company		
SURVEYS & MAPPING				
<b>ESSEX GENERATING AND SWITCHING STATION</b>				
CITY OF NEWARK			ESSEX CO, N.J.	
<b>EPA RESPONSE</b>				
CADD	ND	DATE	AUGUST 13, 1996	SCALE 1" = 80'
FILE		CHECKED		EXAMINED


850010228

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

NO	DATE	DESCRIPTION	DWN	CKD
REVISION				
		<b>PSEG</b> Public Service Electric & Gas Company		
SURVEYS & MAPPING				
<b>ESSEX GENERATING AND SWITCHING STATION</b>				
CITY OF NEWARK			ESSEX CO. N.J.	
<b><i>EPA RESPONSE</i></b>				
CADD	NO	DATE	AUGUST 13, 1996	SCALE 1" = 80'
FILE		CHECKED		EXAMINED


850010229

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

NO	DATE	DESCRIPTION	DWN	CKD
REVISION				
		<b>PSEG</b> Public Service Electric & Gas Company		
SURVEYS & MAPPING				
<b>ESSEX GENERATING AND SWITCHING STATION</b>				
CITY OF NEWARK			ESSEX CO, N.J.	
<b><i>EPA RESPONSE</i></b>				
CADD	NO	DATE	AUGUST 13, 1996	SCALE 1" = 80'
FILE		CHECKED		EXAMINED

850010230

THIS MAP CAN BE FOUND IN THE SITE FILE LOCATED AT: U.S. EPA SUPERFUND RECORDS  
CENTER, 290 BROADWAY, 18<sup>TH</sup> FLOOR, NY, NY 10007

NO	DATE	DESCRIPTION	DWN	CKD
REVISION				
		<b>PSEG</b> Public Service Electric & Gas Company		
SURVEYS & MAPPING				
<b>ESSEX GENERATING AND SWITCHING STATION</b>				
CITY OF NEWARK			ESSEX CO. N.J.	
<b><i>EPA RESPONSE</i></b>				
CADD	NO	DATE	AUGUST 13, 1996	SCALE 1" = 80'
FILE		CHECKED		EXAMINED

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Figure 3.1 Process Flow Diagram  
Low Pressure Turbine/Generators and Boilers  
1915 - 1978

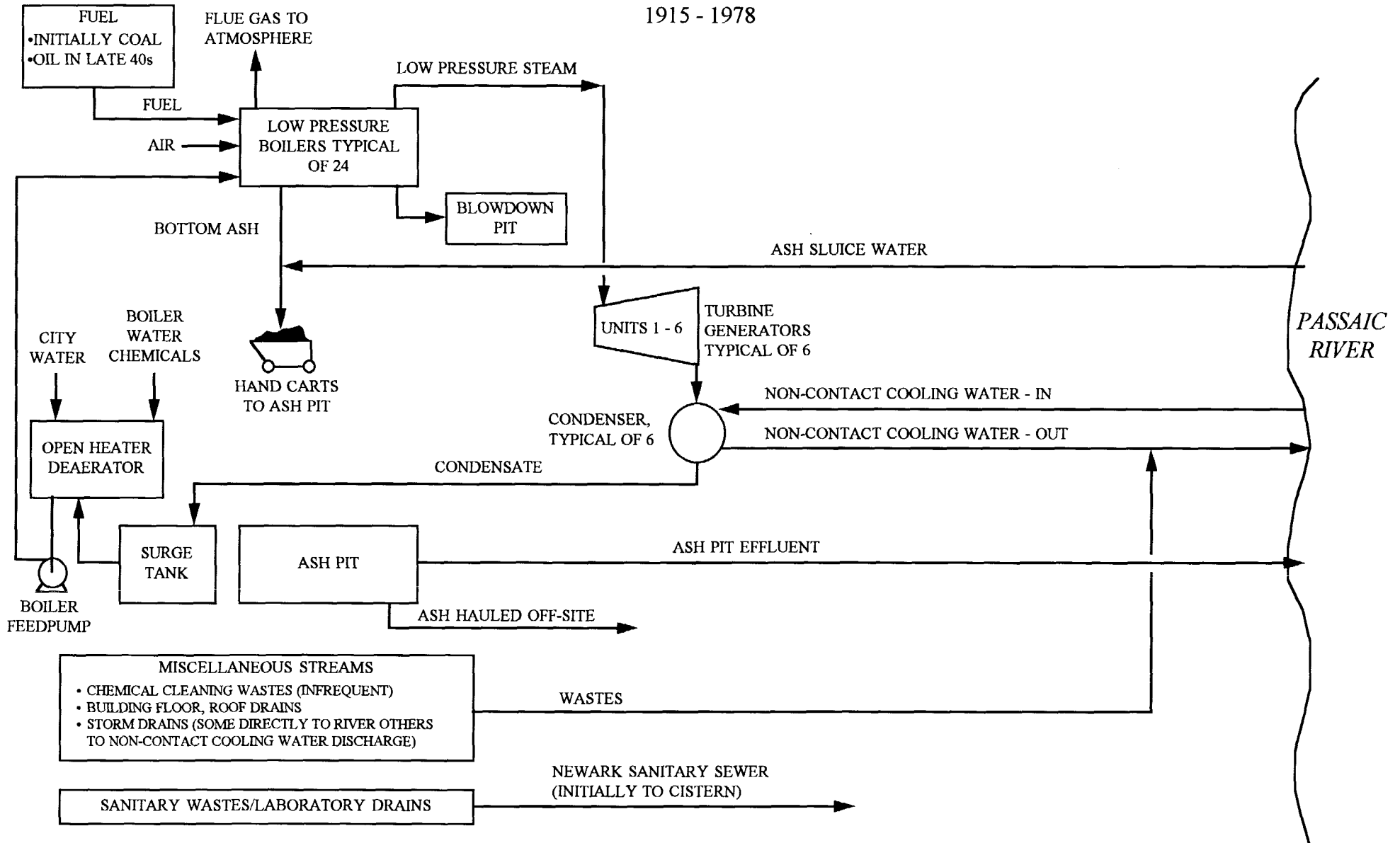


Figure 3.2 Process Flow Diagram  
Addition of Unit No. 7 High Pressure Turbine/Generator & Nos. 25 and 26 Boilers

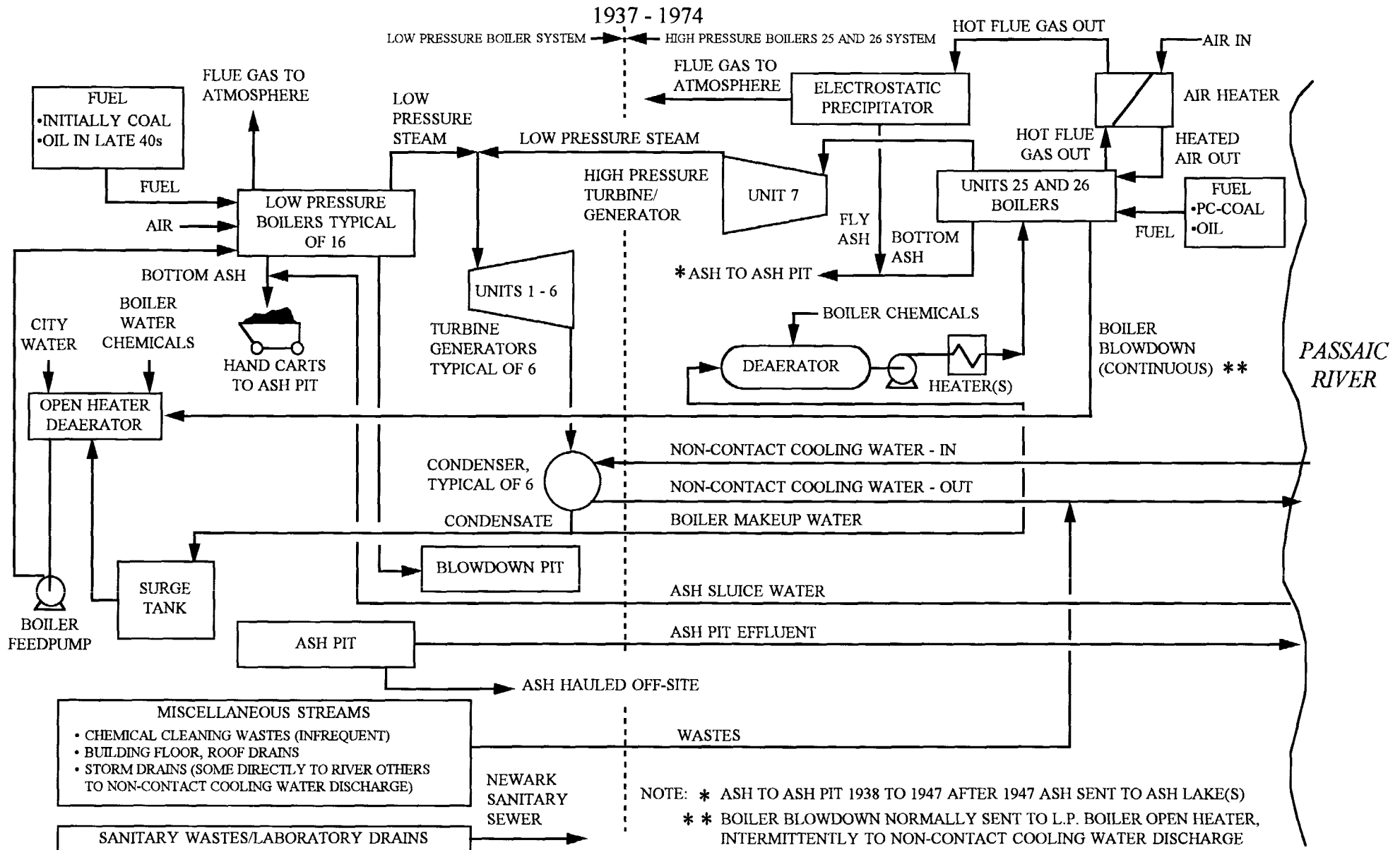


Figure 3.3 Process Flow Diagram  
Addition of New Unit #1 and Ash Lake

1947 - 1978 \*

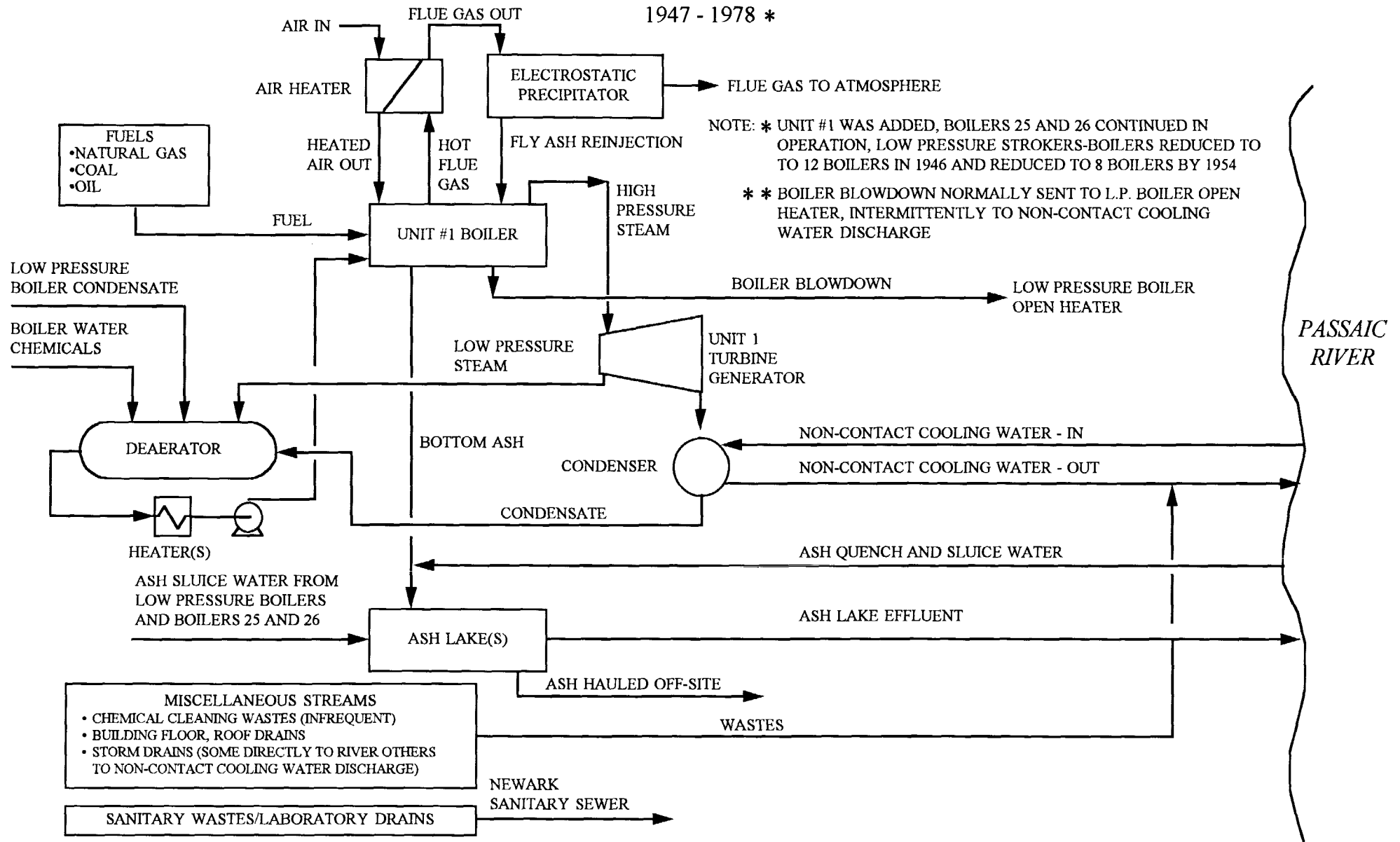
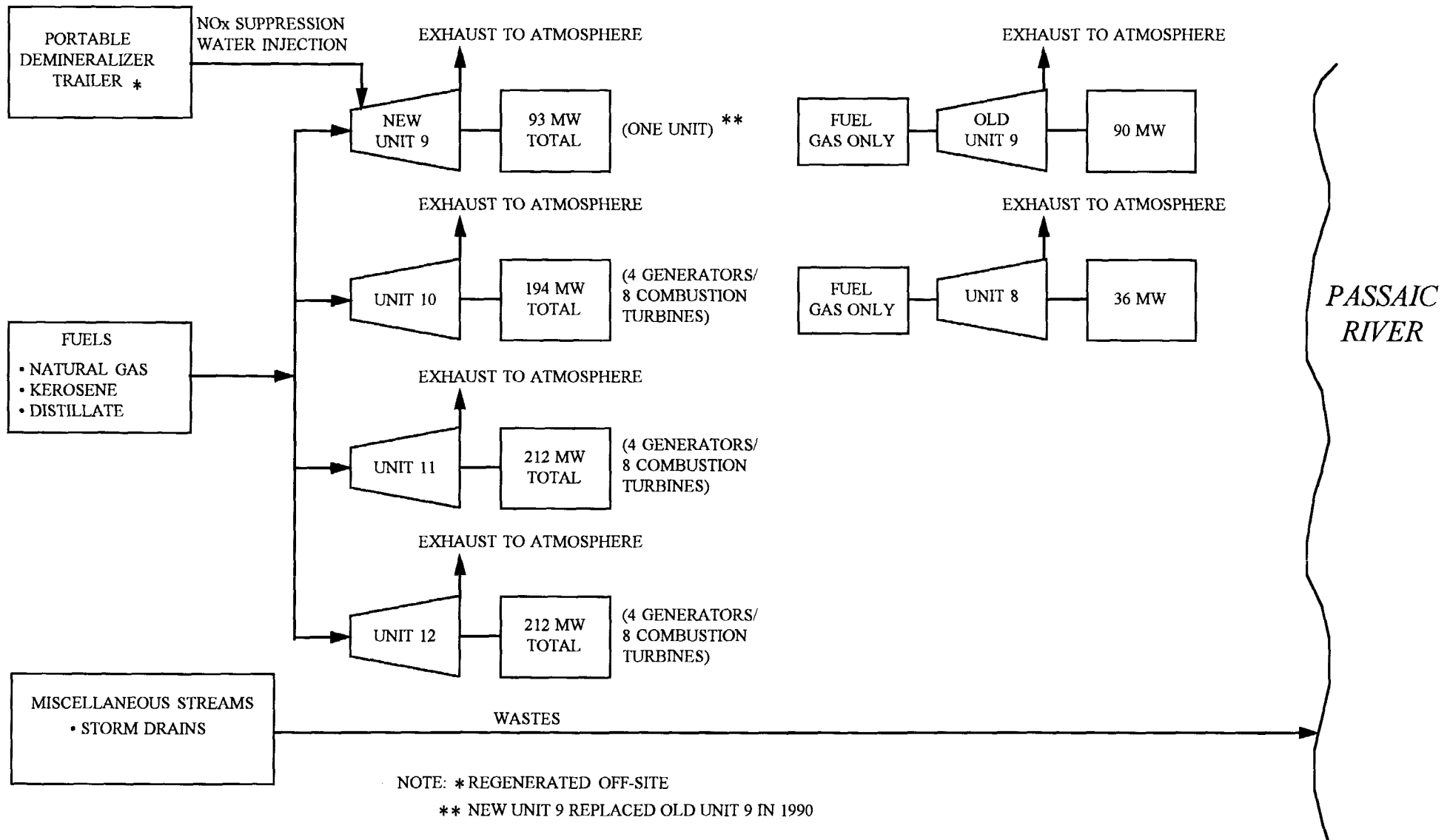


Figure 3.4 Process Flow Diagram  
Simple Cycle Combustion Turbines  
1963 - Present



ATTACHMENT I

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## **ATTACHMENT I**

### **HAZARDOUS AIR POLLUTANTS ESSEX GENERATING STATION**

The two major types of electric generation processes used at the Essex Generating Station were Steam Electric and Combustion Turbine. The two major emission sources associated with these processes were boilers fired by either coal, oil or gas in the case of Steam Electric and combustion turbines fired by gas or oil.

Station specific data for Hazardous Air Pollutants (HAPs) are not available. To provide an estimate of the potential HAPs generated at Essex the following (coal-, gas-, and oil-fired boiler and gas-fired combustion turbine) emission factors and combustion turbine distillate emissions analyses are provided from both the EPRI PISCES Database (ref 1), and relevant literature (ref 2).

#### **Fuel Fired Boilers**

Tables I-1 through I-5 list emission factors for hazardous air pollutants for coal-, oil-, and gas-fired steam-electric power plants that were prepared for the Electric Power Research Institute "EPRI" by Radian Corporation.

The emission factors for coal-fired units are divided into three groups:

1. particulate-phase emissions (Table I-1),
2. vapor-phase inorganics such as Hydrochloric Acid (HCl), and Hydrofluoric Acid (HF) mercury, and, in some cases, selenium (Table I-2),
3. organic substances (Table I-3)

Uncontrolled oil-fired boiler emission factors are presented in Table I-4 for particulate-phase emissions, vapor-phase inorganics, and organic substances. A limited data set was developed for oil-fired boilers with normally operating electrostatic precipitators (ESPs). Based on this data, EPRI recommends 60% of the values in Table I-4 for the metals Arsenic (As), Beryllium (Be), Cadmium (Cd), Chromium (Cr), Cobalt (Co), Lead (Pb), Manganese (Mn), and Nickel (Ni) for oil-fired boilers with ESPs. For organic substances and volatile elements Mercury (Hg), Selenium (Se), Hydrochloric Acid (HCl), and Hydrofluoric Acid (HF), the values in Table I-4 are appropriate for oil-fired boilers with or without an ESP.

There is limited data available from the EPRI Field Chemical Emissions Monitoring (FCEM) Project on HAPs emissions from gas-fired boilers. The corresponding emission factors for gas-fired boilers are presented in Table I-5.

The HAPs emission factors were derived from recent test data produced by EPRI and the U.S. Department of Energy "DOE" that focused on HAPs. The emissions estimating methodology was presented in reference 1, by Radian with the following caveats:

- Actual measurements of HAPs emissions can vary from estimated levels by several orders of magnitude. This variability is primarily external to sampling and analytical variability (i.e., it is caused by site-specific differences in plant design and operation and in daily process variability). Emission estimates developed from such data distributions may differ significantly from measured values.
- As more data become available and are used in the regressions and averages, the predicted factors may change.
- Much of the data fit log-normal distributions. The resulting correlations and geometric mean values provide an appropriate median emission factor for a single unit.
- Site-specific factors at any given plant may be so different from the sample population used to produce these equations that the predictive value may be compromised. For example, co-firing waste tires with oil was not examined at any test site. The oil emission factors would not be good estimators for emissions from such a plant.

It should also be noted that the field data used to develop emission factors for coal-fired boilers were obtained from wall-fired, tangential-fired, and cyclone boilers/furnaces equipped with particulate and/or flue gas desulfurization (FGD) systems. The low pressure, stoker-fired boilers (Nos. 1 through 24) at Essex utilized a different boiler type than the FCEM test units and were not equipped with air pollution control systems.

### **Combustion Turbines**

Measurements of HAPs for utility combustion turbines were performed by Carnot for the Electric Power Research Institute's (EPRI) Gas PISCES (Power Plant Integrated Chemical Emissions Study) field measurement project. The program was jointly sponsored by EPRI and the Gas Research Institute (GRI). The two utility combustion turbines tested by Carnot included the Westinghouse 501AA combustion turbine, without NO<sub>x</sub> controls, and the General Electric Frame 7 combustion turbine equipped with water injection for NO<sub>x</sub> reduction. The HAPs testing for the two utility combustion turbines included measurements of trace metals, semi-volatile organics, and volatile organics.

The results of the metal tests on the two utility turbines are presented in Table I-6. The test results are reported in three discreet groups on each unit: those detected at more than twice the field blank levels, those detected at less than twice or below the field blank levels, and those that were not detected. The measured levels were all low compared to emissions from coal- and oil-fired boilers.

The semi-volatile organic emission results are presented in Table I-7. No polychlorinated biphenyls (PCBs) were measured to detection levels of 2-10 ng/Nm<sup>3</sup>. The levels of polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF) that were detected were orders of magnitude lower than those on municipal solid waste incinerators and other units typically associated with PCDD/PCDF emissions.

Table I-8 present emission factors for the VOCs formaldehyde, benzene, and toluene that are valid at full load operation for the two combustion turbines tested. Testing indicates that VOC emissions generally increase sharply with decreasing load. The trend for CO emissions, not shown here, and Volatile Organic Carbons (VOCs) are similar, indicating that combustion conditions favorable for the destruction of CO will also reduce VOC levels.

The combustion turbines used at Essex generally operate at full load during peak electric demand of the winter and summer months. These combustion turbines are fired primarily on gas with oil firing used as the alternate fuel. Table I-9 provides emission data for HAPs for combustion turbines firing oil. This data provides typical stack concentrations for a variety of HAPs measured for combustion turbines operating in a simple cycle mode. Minimum and maximum concentrations shown may reflect, as noted, Non-Detect analytical results which have been conservatively reported in the EPRI PISCES Database at the sensitivity limit of the analytical method.

## References

1. Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995
2. A Summary of Air Toxic Emissions From Natural Gas-Fired Combustion Turbines", Bruce A. Fangmeier et al, Carnot, AFRC/JFRC Pacific Rim International Conference on Environmental Control of Combustion Process, October 16-20, 1994, Electric Power Research Institute's (EPRI) Gas PISCES Study.

Table I-1 \*\*

**EPRI - Coal Fired Boiler Emission Factors and Correlation Results  
for Particulate-Phase Emissions (lb/trillion Btu)**

Analyte	Predicted Emissions	$r^2$	N	Root MSE	t - Value	$\bar{x}_{\log}$	$SS_{\log x}$
Antimony	$(0.92) x^{0.63}$	0.65	8	0.37	2.45	-0.30	3.8
Arsenic	$(3.1) x^{0.85}$	0.72	34	0.44	2.04	-0.006	27
Beryllium	$(1.2) x^{1.1}$	0.83	17	0.29	2.13	-0.26	4.8
Cadmium	$(3.3) x^{0.5}$	0.78	9	0.24	2.37	-0.55	7.8
Chromium	$(3.7) x^{0.58}$	0.57	38	0.40	2.03	0.31	23
Cobalt	$(1.7) x^{0.69}$	0.57	20	0.42	2.10	0.016	8.3
Lead	$(3.4) x^{0.80}$	0.62	33	0.48	2.04	0.061	18
Manganese	$(3.8) x^{0.60}$	0.57	37	0.39	2.03	0.70	18
Nickel	$(4.4) x^{0.48}$	0.51	25	0.49	2.07	0.28	25

\*\* Ref: Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995

**x** = Coal ppm/ash fraction \* Particulate Emission (lb/million Btu)  
 **$r^2$**  = Correlation coefficient for the regression  
**N** = Number of data points included in the regression  
**Root MSE** = Square root of the mean squared error (MSE) of the regression  
**t** = Two-tail t value ( $t_{0.025}$ ) for N-2 degrees of freedom  
 **$\bar{x}_{\log}$**  = Mean of the log of the x terms  
 **$SS_{\log x}$**  = Sum of Squared Deviations of the log of the x terms

**EXAMPLE CALCULATION**

Coal arsenic concentration = 20 ppm  
 Ash Fraction = 10%  
 Particulate emission = 0.06 lb/million Btu

Mean emission  $E = 3.1(x)^{0.85}$   
 $E = 3.1 (20 \times 0.06/0.1)^{0.85}$   
 $E = 25.6 \text{ lb/trillion Btu}$

The 95% Upper Confidence Interval =  $E * 10^{\left\{ t * \text{RMSE} * \text{Square Root} \left\{ 1/N + ((\log x - \bar{x}_{\log})^2 / SS_{\log x}) \right\} \right\}}$

**Table I-2 \*\***

**EPRI - Recommended Emission Factor  
as Percent of Coal Input  
Bituminous Coals**

<b>Emission</b>	<b>Control Device</b>	<b>Number of Sites</b>	<b>Average Reduction</b>	<b>95% Confidence Interval</b>	<b>Recommended Emission Factor as Percent of Coal Input</b>
Mercury	ESP	17	26%	±14%	70%
Mercury	None	---	---	---	100%
Selenium	None	15	45%	± 13%	55%
Hydrochloric Acid	None	15	-1%	± 13%	100%
Hydrofluoric Acid	None	12	11%	± 19%	90%

**\*\* Ref; Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995**

Table I-3 \*\*

**EPRI - Coal-Fired Boiler  
Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
1-Chloronaphthalene	9	0	0	E		<0.18	<7.8
1-Naphthylamine	8	1	1	D	0.011		
1,1-Dichloroethane	12	1	12	D	0.89	0.40	2.0
1,1-Dichloroethane	12	0	0	E		<0.4	<12
1,1,2-Trichloroethane	12	0	0	E		<0.4	<12
1,1,2,2-Tetrachloroethane	12	0	0	E		<0.4	<10
1,2-Dibromomethane	2	1	2	D	2.6	0.0	1.3e+0.6
1,2-Dichlorobenzene	11	0	0	E		<0.2	<3.5
1,2-Dichloroethane	9	0	0	E		<0.4	<5.2
1,2-Dichloropropane	12	0	0	E		<0.4	<6
1,2-Diphenylhydrazine	8	0	0	E		<2.4	<33
1,2,4-Trichlorobenzene	9	1	9	D	1.5	0.3	8.6
1,2,4,5-Tetrachlorobenzene	8	0	0	E		<0.15	<5
1,3-Dichlorobenzene	11	1	11	D	1.0	0.24	4.4
1,4-Dichlorobenzene	11	1	11	D	1.1	0.25	4.8
2-Butanone	11	2	11	D	3.1	1.8	5.4
2-Chloronaphthalene	8	2	2	C	0.0005	0.0	0.017
2-Chlorophenol	6	0	0	E		<0.2	<5
2-Hexanone	10	3	10	C	3.2	1.8	5.7
2-Methylnaphthalene	19	8	11	A	0.036	0.017	0.077
2-Methylphenol	8	0	0	E		<1.8	<7.8
2-Naphthylamine	7	0	0	E		<0.54	<5
2-Nitroaniline	7	0	0	E		<0.15	<24
2-Nitrophenol	7	0	0	E		<2.4	<7.8
2-Picoline	9	0	0	E		<0.3	<7.8
2,3,4,6-Tetrachlorophenol	9	0	0	E		<0.14	<16
2,3,7,8-TCDD equivalents	10	10	10	A	0.000002	4.40e-07	0.000012
2,4-Dichlorophenol	9	0	0	E		<0.14	<7.8
2,4-Dimethylphenol	9	0	0	E		<0.35	<7.8
2,4-Dinitrophenol	9	0	0	E		<1.8	<39
2,4-Dinitrotoluene	13	4	10	C	0.20	0.038	0.94

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Table I -3 (Continued)

**EPRI - Coal-Fired Boiler  
Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
2,4,5-Trichlorophenol	9	0	0	E		<0.12	7.8
2,4,6-Trichlorophenol	9	0	0	E		<0.12	<7.8
2,5-Dimethylbenzaldehyde	2	2	2	C	14	9.1	23
2,6-Dichlorophenol	9	0	0	E		<0.19	<7.8
2,6-Dinitrotoluene	13	2	8	D	0.11	0.0095	1.3
3-Chloropropylene	2	2	2	C	9.1	5.5	15
3-Methylcholanthrene	10	0	0	E		<0.005	<7.8
3-Nitroaniline	9	0	0	E		<0.14	<39
3,3-Dichlorobenzidine	9	0	0	E		<0.13	<16
3,4-Methylphenol	2	2	2	C	0.71	0.21	2.4
4-Aminobiphenyl	10	0	0	E		<0.27	<7.8
4-Bromophenyl phenyl ether	9	0	0	E		<0.14	<7.8
4-Chloro-3-methylphenol	9	0	0	E		<0.19	<7.8
4-Chlorophenyl phenyl ether	9	0	0	E		<0.14	<7.8
4-Ethyl toluene	2	2	2	C	2.8	0.0001	1.3e+05
4-Methyl-2-pentanone	7	2	6	D	2.3	1.1	4.7
4-Methylphenol	9	2	6	D	1.3	1.1	1.5
4-Nitroaniline	9	0	0	E		<3.5	<39
4-Nitrophenol	9	0	0	E		<0.23	<39
4,6-Dinitro-o-cresol	9	0	0	E		<0.2	<39
5-Methylchrysene	3	1	3	D	0.0006	0.0001	0.0054
7H-Dibenzo(c,g)carbazole	3	0	0	E		<0.001	<0.016
7,12-Dimethylbenzo(a)anthracene	10	0	0	E		<0.005	<19
Acenaphthene	24	11	15	A	0.024	0.011	0.050
Acenaphthylene	24	12	13	A	0.0078	0.0044	0.014
Acetaldehyde	19	11	19	A	3.2	1.1	8.9
Acetone	11	3	11	C	1.1	0.37	3.2
Acetophenone	15	8	14	A	1.2	0.74	1.9
Acrolein	12	5	12	B	1.9	0.51	7.2
Aniline	9	0	0	E		<0.24	<7.8
Anthracene	24	11	15	A	0.013	0.0054	0.030

Table I -3 (Continued)

**EPRI - Coal-Fired Boiler**  
**Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Benzaldehyde	7	2	7	D	4.2	0.83	21
Benzene	25	23	25	A	3.9	1.9	8.0
Benzidine	10	0	0	E		<2.4	<7.8
Benzoic acid	11	5	11	B	22	9.5	53
Benzo(a)anthracene	27	11	15	A	0.0075	0.0032	0.017
Benzo(a)pyrene	27	7	13	B	0.0019	0.0008	0.0045
Benzo(a)pyrene equivalents	11	11	11	A	0.0048	0.0019	0.012
Benzo(b,j&k)fluoranthene	26	10	14	A	0.0096	0.0040	0.023
Benzo(e)pyrene	7	4	7	C	0.0036	0.0013	0.010
Benzo(g,h,i)perylene	26	6	12	B	0.0015	0.0007	0.0031
Benzyl alcohol	9	2	9	D	2.0	1.4	2.9
Benzylchloride	6	4	6	C	0.28	0.0042	19
Biphenyl	9	6	9	B	0.16	0.022	1.2
bis(2-Chloroethoxy)methane	8	0	0	E		<0.17	<7.8
bis(2-Chloroethyl)ether	9	0	0	E		<0.18	<7.8
bis(2-Chloroisopropyl)ether	10	0	0	E		<0.22	<7.8
bis(2-Ethylhexyl)phthalate	11	7	11	A	3.6	2.0	6.2
Bromodichloromethane	10	0	0	E		<0.49	<6
Bromoform	10	0	0	E		<0.42	<10
Bromomethane	13	4	13	C	0.89	0.38	2.1
Butylbenzylphthalate	9	2	2	C	0.30	0.24	0.38
Carbon disulfide	14	7	13	B	1.1	0.40	2.9
Carbon tetrachloride	14	0	0	E		<0.42	<6
Chlorobenzene	15	1	1	D	0.16		
Chloroethane	13	1	11	D	0.53	0.26	1.1
Chloroform	12	1	11	D	0.55	0.26	1.2
Chloromethane	10	3	10	C	1.1	0.23	5.1
Chrysene	26	9	12	A	0.0055	0.0028	0.011
cis-1,2-Dichloroethene	6	0	0	E		<0.42	<3.1
cis-1,3-Dichloropropene	14	1	14	D	0.72	0.37	1.4
Crotonaldehyde	4	0	0	E		<0.1	<7.1

Table I -3 (Continued)

**EPRI - Coal-Fired Boiler**  
**Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Dibenzofuran	14	4	14	C	0.58	0.21	1.6
Dibenzo(a,e) pyrene	3	0	0	E		<0.0003	<0.003
Dibenzo(a,h)acridine	3	0	0	E		<0.001	<0.002
Dibenzo(a,h)anthracene	26	3	12	C	0.0009	0.0003	0.0024
Dibenzo(a,i)acridine	3	1	1	D	0.0010		
Dibenzo(a,i)pyrene	3	0	0	E		<0.001	<0.004
Dibenzo(a,j)acridine	9	0	0	E		<0.2	<7.8
Dibromochloromethane	12	0	0	E		<0.42	<6
Dibutylphthalate	9	1	2	D	0.11	0.0005	28
Dichlorobromomethane	2	0	0	E		<0.42	<0.45
Dichloromethane	2	0	0	E		<1.6	<2
Diethylphthalate	10	2	2	C	0.20	0.020	2.0
Dimethylphenethylamine	9	0	0	E		<2.4	<40
Dimethylphthalate	9	1	2	D	0.090	0.0	1.0e+03
Di-n-butylphthalate	3	0	0	E		<1.9	<3
Di-n-octylphthalate	9	0	0	E		<0.21	<7.8
Diphenylamine	9	0	0	E		<0.13	<7.8
Ethyl methanesulfonate	9	0	0	E		<0.17	<7.8
Ethylbenzene	16	4	16	C	0.80	0.35	1.8
Fluoranthene	24	13	22	A	0.15	0.059	0.39
Fluorene	24	11	23	B	0.14	0.049	0.40
Formaldehyde	26	10	26	B	2.6	1.4	4.8
Hexachlorobenzene	14	0	0	E		<0.001	<7.8
Hexachlorobutadiene	15	0	0	E		<0.001	<7.8
Hexachlorocyclopentadiene	13	0	0	E		<0.001	<7.8
Hexachloroethane	13	0	0	E		<0.001	<7.8
Hexaldehyde	2	1	2	D	5.7	0.0036	9.2e+03
Indeno(1,2,3-c,d)pyrene	25	7	12	B	0.0017	0.0008	0.0039
Iodomethane	2	2	2	C	2.0	0.0	2.3e+09
Isophorone	10	1	10	D	1.2	0.32	4.3
Methyl chloroform	8	3	7	C	0.61	0.24	1.5

Table I -3 (Continued)

**EPRI - Coal-Fired Boiler**  
**Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Methyl methacrylate	2	1	1	D	1.1		
Methyl methanesulfonate	9	0	0	E		<1.2	<17
Methylene chloride	7	4	7	C	3.6	0.63	21
m/p-Tolualdehyde	2	2	2	C	3.2	0.0012	8.4e+03
m/p-Xylene	13	8	13	A	0.82	0.28	2.4
Naphthalene	23	12	20	A	0.62	0.36	1.1
n-Butyraldehyde	2	1	2	D	8.3	0.0001	5.9e+05
n-Hexane	2	2	2	C	0.49	0.0	1.7e+06
Nitrobenzene	9	0	0	E		<0.19	<7.8
N-Nitrosodibutylamine	6	0	0	E		<2.4	<7.8
N-Nitrosodimethylamine	10	0	0	E		<0.34	<7.8
N-Nitroso-di-n-butylamine	3	0	0	E		<0.32	<5
N-Nitrosodiphenylamine	9	0	0	E		<0.14	<7.8
N-Nitrosodipropylamine	9	0	0	E		<0.21	<7.8
N-Nitrosopiperidine	9	0	0	E		<0.24	<7.8
o-Tolualdehyde	2	1	2	D	2.9	0.0	6.0e+06
o-Xylene	12	3	12	C	0.44	0.25	0.78
p-Chloroaniline	9	0	0	E		<0.18	<7.8
p-Dimethylaminoazobenzene	9	0	0	E		<0.17	<7.8
Pentachlorobenzene	9	0	0	E		<0.12	<7.8
Pentachloronitrobenzene	9	0	0	E		<0.54	<7.8
Pentachlorophenol	13	0	0	E		<0.001	<39
Perylene	2	1	2	D	0.0035	0.0	7.2e+15
Phenacetin	9	0	0	E		<0.014	<7.8
Phenanthrene	24	13	24	A	0.42	0.19	0.91
Phenol	13	7	13	B	3.3	1.5	7.1
Pronamide	9	0	0	E		<0.17	<7.8
Propanal	2	1	3	D	2.3	0.0	1.1e+06
Propionaldehyde	6	4	6	C	1.8	0.11	30
Pyrene	24	10	21	B	0.066	0.022	0.19
Pyridine	9	0	0	E		<0.28	<7.8

**Table I -3 (Continued)**

**EPRI - Coal-Fired Boiler  
Organic Substance Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Quinoline	3	0	0	E		<0.009	<5.6
Styrene	16	4	12	C	0.70	0.34	1.4
Tetrachloroethylene	15	3	10	C	0.42	0.24	0.75
Toluene	23	16	23	A	1.7	0.90	3.1
trans-1,2-Dichloroethene	12	0	0	E		<0.42	<6
trans-1,3-Dichloropropene	14	0	0	E		<0.42	<6.9
Trichloroethylene	14	0	0	E		<0.42	<6
Trichlorofluoromethane	12	5	12	B	0.87	0.33	2.3
Trichloromethane	2	1	2	D	3.3	0.0	4.7e+05
Valeraldehyde	2	2	2	C	7.6	0.049	1.2e+03
Vinyl acetate	13	1	3	D	0.31	0.14	0.69
Vinyl chloride	12	1	12	D	0.73	0.30	1.8

**\*\* Ref; Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995**

**\*Data quality:**

- A = Five or more detected values, no more than 50% nondetects in statistics.
- B = Four or more detected values, no more than 67% nondetects in statistics.
- C = Two or more detected values, no more than 75% nondetects in statistics.
- D = One or more detected values, no limit on nondetects in statistics.
- E = Substance has not been detected.

LCI = Lower Confidence Interval  
UCI = Upper Confidence Interval

Table I-4 \*\*

**EPRI - Uncontrolled Oil-Fired Boiler  
Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Arsenic	13	12	13	A	5.1	2.5	11
Beryllium	13	5	13	B	0.15	0.05	0.46
Cadmium	13	12	13	A	1.2	0.42	3.1
Chloride (as HCl)	12	12	12	A	2370	1870	3000
Chromium	13	12	13	A	5.2	3.1	8.7
Cobalt	7	7	7	A	32	14	76
Fluoride as (HF)	10	10	10	A	110	48	270
Lead	13	11	13	A	8.0	3.7	17
Manganese	13	13	13	A	14	8.3	23
Mercury	17	9	12	A	0.48	0.23	1.0
Nickel	14	14	14	A	710	470	1080
Selenium	17	11	17	A	2.1	0.81	5.6
1-Chloronaphthalene	2	0	0	E		<5.9	<6.5
1-Naphthylamine	2	0	0	E		<5.9	<6.5
1,1-Dichloroethane	2	0	0	E		<0.49	<1.9
1,1-Dichloroethene	2	0	0	E		<0.49	<1.9
1,1,1-Trichloroethane	2	2	2	C	1.1	0.0074	160
1,1,2-Trichloroethane	2	0	0	E		<0.48	<0.49
1,1,2,2-Tetrachloroethane	2	0	0	E		<0.48	<0.49
1,2-Dibromomethane	2	0	0	E		<1.7	<2.9
1,2-Dichloroethane	2	0	0	E		<1.2	<2.1
1,2-Dichlorobenzene	2	0	0	E		<0.49	<6.5
1,2-Dichloroethane	2	0	0	E		<0.49	<1.9
1,2-Dichloropropane	2	0	0	E		<0.49	<5.9
1,2-Diphenylhydrazine	2	0	0	E		<5.9	<6.5
1,2,4-Trichlorobenzene	2	0	0	E		<5.9	<6.5
1,2,4,5-Tetrachlorobenzene	2	0	0	E		<5.9	<6.5
1,3-Butadiene	2	0	0	E		<0.14	
1,3-Dichlorobenzene	2	0	0	E		<0.49	<6.5
1,4-Dichlorobenzene	2	0	0	E		<0.49	<6.5
2-Butanone	2	0	0	E		<4.9	<19
2-Chloronaphthalene	2	0	0	E		<5.9	<6.5
2-Chlorophenol	2	0	0	E		<5.9	<6.5
2-Hexanone	4	0	0	E		<4.8	<19

Table I-4 (Continued)

**EPRI - Uncontrolled Oil-Fired Boiler  
Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
2-Methylnaphthalene	11	9	9	A	0.029	0.018	0.047
2-Methylphenol	2	0	0	E		<5.9	<6.5
2-Naphthylamine	2	0	0	E		<5.9	<6.5
2-Nitroaniline	2	0	0	E		<30	<32
2-Nitrophenol	2	0	0	E		<5.9	<6.5
2-Picoline	2	0	0	E		<5.9	<6.5
2,3,4,6-Tetrachlorophenol	2	0	0	E		<12	<13
2,3,7,8-TCDD equivalents	4	3	3	C	0.000008	0.000001	0.00012
2,4-Dichlorophenol	2	0	0	E		<5.9	<6.5
2,4-Dimethylphenol	2	0	0	E		<5.9	<6.5
2,4-Dinitrophenol	2	0	0	E		<30	<32
2,4-Dinitrotoluene	2	0	0	E		<5.9	<6.5
2,4,5-Trichlorophenol	2	0	0	E		<5.9	<6.5
2,4,6-Trichlorophenol	2	0	0	E		<5.9	<6.5
2,6-Dichlorophenol	2	0	0	E		<5.9	<6.5
2,6-Dinitrotoluene	2	0	0	E		<5.9	<6.5
3-Methylcholanthrene	11	0	0	E		0.006	<330
3-Nitroaniline	2	0	0	E		<30	<32
3,3-Dichlorobenzidine	2	0	0	E		<12	<13
4-Aminobiphenyl	2	0	0	E		<5.9	<6.5
4-Bromophenyl phenyl ether	2	0	0	E		<5.9	<6.5
4-Chloro-3-methylphenol	2	0	0	E		<5.9	<6.5
4-Chlorophenyl phenyl ether	2	0	0	E		<5.9	<6.5
4-Methylphenol	2	0	0	E		<5.9	<6.5
4-Nitroaniline	2	0	0	E		<30	<32
4-Nitrophenol	2	0	0	E		<30	<32
4,6-Dinitro-o-cresol	2	0	0	E		<30	<32
6-Nitrobenzo(a)pyrene	2	0	0	E		<0.01	
7,12-Dimethylbenzo(a)anthracene	11	0	0	E		<0.002	<16
Acenaphthene	18	4	16	C	0.012	0.0052	0.029
Acenaphthylene	18	1	1	D	0.0020		
Acetaldehyde	2	1	2	D	6.6	0.16	270
Acetone	2	0	0	E		<4.9	<19
Acetophenone	2	0	0	E		<5.9	<6.5

Table I-4 (Continued)

**EPRI - Uncontrolled Oil-Fired Boiler  
Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Acrolein	2	0	0	E		<10	<12
Aniline	2	0	0	E		<5.9	<6.5
Anthracene	18	2	14	D	0.0044	0.0030	0.0066
Benzaldehyde	2	0	0	E		<16	<20
Benzene	18	11	16	A	1.10	0.80	1.5
Benzoic acid	2	2	2	C	73	2.1	2500
Benzo(a)anthracene	18	3	15	C	0.0094	0.0047	0.019
Benzo(a)pyrene	18	0	0	E		<0.004	<6.5
Benzo(a)pyrene equivalents	18	4	4	B	0.012	0.0005	0.026
Benzo(b,j&k)fluoranthene	17	2	14	D	0.0056	0.0037	0.0086
Benzo(g,h,i)perylene	18	2	15	D	0.0068	0.0044	<0.010
Benzyl alcohol	2	0	0	E		<5.9	<6.5
bis(2-Chloroethoxy)methane	2	0	0	E		<5.9	<6.5
bis(2-Chloroethyl)ether	2	0	0	E		<5.9	<6.5
bis(2-Chloroisopropyl)ether	2	0	0	E		<5.9	<6.5
bis(2-Ethylhexyl)phthalate	2	0	0	E		<5.9	<6.5
Bromodechloromethane	2	0	0	E		<0.49	<1.9
Bromoform	2	0	0	E		<0.48	<0.49
Bromomethane	2	0	0	E		<0.49	<1.9
Butylbenzylphthalate	2	0	0	E		<5.9	<6.5
Carbon disulfide	2	0	0	E		<0.49	<1.9
Carbon tetrachloride	4	0	0	E		<0.48	<1.9
Chlorobenzene	4	0	0	E		<0.34	<0.69
Chloroethane	2	0	0	E		<0.48	<1.9
Chloroform	4	0	0	E		<0.48	<1.9
Chloromethane	2	0	0	E		<0.48	<1.9
Chrysene	18	3	16	C	0.0098	0.0051	0.019
cis-1,2-Dichloroethene	2	0	0	E		<0.49	<1.9
Dibenzofuran	2	0	0	E		<5.9	<6.5
Dibenzo(a,h)anthracene	18	1	12	D	0.0046	0.0031	0.0069
Dibenzo(a,j)acridine	2	0	0	E		<5.9	<6.5
Dibromochloromethane	2	0	0	E		<0.48	<0.49
Dibutylphthalate	2	0	0	E		<5.9	<6.5
Dichloromethane	2	2	2	C	33	9.7	110

Table I-4 (Continued)

**EPRI - Uncontrolled Oil-Fired Boiler  
Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Diethylphthalate	2	0	0	E		<5.9	<6.5
Dimethylphenethylamine	2	0	0	E		<5.9	<6.5
Dimethylphthalate	2	0	0	E		<5.9	<6.5
Di-n-octylphthalate	2	0	0	E		<5.9	<6.5
Diphenylamine	2	0	0	E		<5.9	<6.5
Ethyl methanesulfonate	2	0	0	E		<5.9	<6.5
Ethylbenzene	4	2	4	D	0.29	0.19	0.45
Fluoranthene	18	7	16	B	0.014	0.0064	0.030
Fluorene	18	10	16	A	0.012	0.0068	0.022
Formaldehyde	18	12	18	A	18	7.4	43
Indeno (1,2,3,-c,d) pyrene	18	2	15	D	0.0069	0.0046	0.010
Isophorone	2	0	0	E		<5.9	<6.5
Methyl bromide	2	0	0	E		<1.2	<1.7
Methyl chloroform	2	2	2	C	11	0.051	2500
Methyl methanesulfonate	2	0	0	E		<5.9	<6.5
m/p-Xylene	2	2	2	C	1.2	0.73	2.1
Naphthalene	18	14	18	A	0.83	0.30	2.3
Nitrobenzene	2	0	0	E		<5.9	<6.5
N-Nitrosodibutylamine	4	0	0	E		<5.9	<6.5
N-Nitrosodiethylamine	2	0	0	E		<0.04	<0.05
N-Nitrosodimethylamine	4	0	0	E		<0.03	<6.5
N-Nitrosodiphenylamine	2	0	0	E		<5.9	<6.5
N-Nitrosodipropylamine	4	0	0	E		<0.4	<6.5
N-Nitrosomorpholine	2	0	0	E		<0.4	<0.5
N-Nitrosopiperidine	4	0	0	E		<0.04	<6.5
N-Nitrosopyrrolidine	2	0	0	E		<0.04	<0.05
o-Xylene	4	2	4	D	0.35	0.15	0.84
p-Chloroaniline	2	0	0	E		<5.9	<6.5
p-Dimethylaminoazobenzene	2	0	0	E		<5.9	<6.5
Pentachlorobenzene	2	0	0	E		<5.9	<6.5
Pentachloronitrobenzene	2	0	0	E		<5.9	<6.5
Pentachlorophenol	2	0	0	E		<30	<32
Phenacetin	2	0	0	E		<5.9	<6.5
Phenanthrene	18	15	16	A	0.040	0.018	0.092

Table I-4 (Continued)

**EPRI - Uncontrolled Oil-Fired Boiler  
Emission Factors (lb/trillion Btu)**

Chemical Substance	Sites Tested	Sites Detected	Sample Size	DQ*	Log-Normal		
					Mean	LCI	UCI
Phenol	2	2	2	C	10	1.3	83
Pronamide	2	0	0	E		<5.9	<6.5
Pyrene	19	5	15	B	0.012	0.0064	0.024
Pyridine	2	0	0	E		<5.9	<6.5
Styrene	2	0	0	E		<0.48	<0.49
Tetrachloroethylene	4	0	0	E		<0.41	<1
Toluene	11	11	11	A	12	6.0	25
trans-1,2-Dichloroethene	2	0	0	E		<0.49	<1.9
trans-1,2-Dichloropropene	2	0	0	E		<0.49	<1.9
Trichloroethylene	4	0	0	E		<0.49	<1.9
Trichlorofluoromethane	4	3	4	C	1.7	0.23	13
Vinyl acetate	2	0	0	E		<4.9	<19
Vinyl chloride	4	0	0	E		<0.49	<1.9

\*\* Ref: Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995

\*Data quality:

- A = Five or more detected values, no more than 50% nondetects in statistics.
- B = Four or more detected values, no more than 67% nondetects in statistics.
- C = Two or more detected values, no more than 75% in statistics.
- D = One or more detected values, no limit on nondetects in statistics.
- E = Substance has not been detected.

Table I-5 \*\*

EPRI - Uncontrolled Gas-Fired Boiler  
Emission Factors (lb/trillion Btu)

Substances	Sites Tested	Sites Detected <sup>a</sup>	Sample Size <sup>b</sup>	DQ <sup>c</sup>	Arithmetic Mean Emission Factor
Arsenic	2	2	2	C	0.23
Beryllium	2	0	0	E	<0.01
Cadmium	2	1	1	D	0.04
Chromium	2	2	2	C	1.1
Cobalt	2	1	1	D	0.08
Lead	2	2	2	C	0.4
Manganese	2	2	2	C	0.4
Mercury <sup>d</sup>	2	1	2	D	0.0008
Nickel	2	2	2	C	2.4
Selenium	2	0	0	E	<0.02
Benzene	8	2	5	D	0.8
Formaldehyde <sup>e</sup>	9	8	9	A	175(0-410)
Toluene	2	2	2	C	10
Benzo(a)pyrene equivalents	2	0	0	E	ND <sup>f</sup>
2,3,7,8-TCDD equivalents	1	1	1	D	0.0000012

\*\* Ref: Field Chemical Emissions Monitoring Project: Guidelines for Estimating Trace Substance Emissions from Fossil Fuel Steam Electric Plants, EPRI - DCN 95-213-152-64, August 1995

a

Number of times the substance was quantified.

b

The number of site values used to calculate the mean and confidence interval. (Individual values with detection limits greater than two times the highest quantified value were not included in the mean.)

c

Data quality:

A = Five or more detected values, no more than 50% nondetects in statistics.

B = Four or more detected values, no more than 67% nondetects in statistics.

C = Two or more detected values, no more than 75% nondetects in statistics.

D = One or more detected values, no more on nondetects in statistics.

E = substance has not been detected.

d

Based on natural gas analysis, not detected in stack gas at higher concentration.

e

Median value and confidence intervals are 34, 7 to 150.

f

ND = Not detected.

Table I - 6

**EPRI - Gas Fired Simple Cycle Combustion Turbine  
Hazardous Metals Emission Factors (lb/trillion Btu)**

<b>Metal</b>	<b>Westinghouse 501 AA</b>	<b>General Electric Frame 7</b>
<i><b>Metals Detected Above Field Blank Level:</b></i>		
Barium	6.6	3.8
Chromium	1.8	1.9
Copper	3.1	6.2
Lead	--	0.53
Manganese	3.5	--
Nickel	1.6	1.2
<i><b>Metals Detected At Field Blank Level:</b></i>		
Arsenic	--	0.18
Cobalt	0.50	--
Lead	1.00	--
Manganese	--	4.5
Mercury	0.69	--
Molybdenum	5.53	3.7
Phosphorous	17.8	11.9
<i><b>Metals Not Detected:</b></i>		
Arsenic	ND<0.10	--
Beryllium	ND<0.03	ND<0.02
Cadmium	ND<0.10	ND<0.07
Cobalt	--	ND<0.22
Mercury	--	ND<0.55
Selenium	ND<0.09	ND<0.06
Vanadium	ND<0.20	ND<0.13

Ref: 2 "A Summary of Air Toxic Emissions From Natural Gas-Fired Combustion Turbines", Bruce A. Fangmeier et al, Carnot, AFRC/JFRC Pacific Rim International Conference on Environmental Control of Combustion Process, October 16-20, 1994, Electric Power Research Institute's (EPRI) Gas PISCES Study.

Table I - 7

**EPRI - Gas Fired Simple Cycle Combustion Turbine  
Hazardous Semi-Volatile Organic Emission Factors (lb/trillion Btu)**

Species	Westinghouse 501 AA	General Electric Frame 7
<i>PAH (detected species only):</i>		
Naphthalene	0.72	0.28
Phenanthrene	0.111	—
2-Methylnaphthalene	0.162	0.010
<i>PCB:</i>		
All PCB isomers not detected		
<i>PCDD/PCDF (detected species only);</i>		
123478-HxCDD	1.9 X 10 <sup>-5</sup>	
123678- HxCDD	1.3 X 10 <sup>-5</sup>	
123789-HxCDD	2.0 X 10 <sup>-5</sup>	
1234678-HpCDD	4.2 X 10 <sup>-5</sup>	
OCDD	4.8 X 10 <sup>-5</sup>	1.8 X 10 <sup>-5</sup>
2378-TCDF	4.0 X 10 <sup>-5</sup>	
23478-PeCDF	3.2 X 10 <sup>-5</sup>	
123478-HxCDF	4.7 X 10 <sup>-5</sup>	
123678-HxCDF	1.5 X 10 <sup>-5</sup>	
234678-HxCDF	2.0 X 10 <sup>-5</sup>	
1234678-HpCDF	5.7 X 10 <sup>-5</sup>	
OCDF	1.5 X 10 <sup>-5</sup>	
Total TCDD	1.6 X 10 <sup>-4</sup>	
Total PeCDD	1.1 X 10 <sup>-4</sup>	
Total HxCDD	1.5 X 10 <sup>-4</sup>	
Total HpCDD	8.0 X 10 <sup>-5</sup>	1.5 X 10 <sup>-5</sup>
Total TCDF	1.5 X 10 <sup>-4</sup>	
Total PeCDF	2.1 X 10 <sup>-4</sup>	
Total HxCDF	1.4 X 10 <sup>-4</sup>	
Total HpDCF	7.4 X 10 <sup>-5</sup>	

Ref: 2 A Summary of Air Toxic Emissions From Natural Gas-Fired Combustion Turbines", Bruce A. Fangmeier et al, Carnot, AFRC/JFRC Pacific Rim International Conference on Environmental Control of Combustion Process, October 16-20, 1994, Electric Power Research Institute's (EPRI) Gas PISCES Study.

**Table I - 8**

**EPRI - Gas Fired Simple Cycle Combustion Turbine  
Hazardous Volatile Organic Emission Factors (lb/trillion Btu)**

<b>Volatile Organic Compound</b>	<b>Westinghouse 501AA</b>	<b>General Electric Frame 7</b>
Formaldehyde	90.	15.
Benzene	7.	<2
Toluene	60.	20.

Table I-9

**Oil Fired Simple Cycle Combustion Turbine  
Hazardous Air Pollutants Identified By Title III of the  
1990 Clean Air Act Amendments (CAAA) reported in PISCES Database**

<u>Substance</u>	<u>Minimum Stack Concentration mg/Nm3 **</u>	<u>Maximum Stack Concentration mg/Nm3 **</u>	<u>Turbine Type</u>	<u>MW</u>	<u>Oil Type</u>	<u>Stack Flow</u>	<u>Stack Flow Units</u>	<u>Stack Conditions</u>
Acenaphthene	8.6 E - 6 **	190. E - 6	Simple-	62	distillate	509,595	dscfm	Temp=336 deg. F, Moisture=9.8%,
Acenaphthylene	8.6 E - 6 **	21 E - 6	Simple-	17	diesel	158,400	dscfm	Temp=987 deg. F, Moisture=5.7%,
Anthracene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Antimony		1.3 E - 4 **	Simple-	61.5	No. 2 fuel oil	201	m3/sec	
Arsenic	4.3 E - 4	5.1 E - 4	Simple-	61.9	No. 2 fuel oil	205	m3/sec	
Barium	4.8 E - 4	37. E - 4	Simple-	61.5	No. 2 fuel oil	201	m3/sec	
Benz(a)anthracene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Benzo(a)pyrene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Benzo(b+k)fluoranthene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Benzo(g,h,i)perylene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Beryllium	8.6 E - 6	37 E - 6	Simple-	61.9	No. 2 fuel oil	205	m3/sec	
Cadmium	3.9 E - 4	1.4 E - 2	Simple-	61.5	No. 2 fuel oil	201	m3/sec	
Chromium	7.7 E - 3	1.8 E - 2	Simple-	61.5	No. 2 fuel oil	201	m3/sec	
Chrysene		8.6 E - 6 **	Simple-	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Cobalt	7.1 E - 6	83. E - 6	Simple-	61.9	No. 2 fuel oil	205	m3/sec	
Copper	4.5 E - 2	6.4 E - 2	Simple-	61.9	No. 2 fuel oil	205	m3/sec	

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Table I-9 Cont.

**Oil Fired Simple Cycle Combustion Turbine  
Hazardous Air Pollutants Identified By Title III of the  
1990 Clean Air Act Amendments (CAAA) reported in PISCES Database**

<u>Substance</u>	<u>Minimum Stack Concentration mg/Nm3 **</u>	<u>Maximum Stack Concentration mg/Nm3 **</u>	<u>Turbine Type</u>	<u>MW</u>	<u>Oil Type</u>	<u>Stack Flow</u>	<u>Stack Flow Units</u>	<u>Stack Conditions</u>
Dibenz(a,h)anthracene		8.6 E - 6 **	Simple-Cycle	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Fluoranthene	1.4 E - 5	5.2 E - 5	Simple-Cycle	62	distillate	509,595	dscfm	Temp=336 deg. F, Moisture=9.8%,
Fluorene	8.6 E - 6 **	110. E - 6	Simple-Cycle	17	diesel	158,400	dscfm	Temp=987 deg. F, Moisture=5.7%,
Indeno(1,2,3-c,d)pyrene		8.3 E - 6 **	Simple-Cycle	17	diesel	153,330	dscfm	Temp=985 deg. F, Moisture=4.9%,
Lead	2.2 E - 2	8.3 E - 2	Simple-Cycle	61.5	No. 2 fuel oil	201	m3/sec	
Manganese	1.4 E - 6	5.1 E - 6	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Mercury	2.5 E - 3	22. E - 3	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Molybdenum	8.8 E - 5 **	100. E - 5	Simple-Cycle	61.5	No. 2 fuel oil	201	m3/sec	
Naphthalene	1.7 E - 2	2.2 E - 2	Simple-Cycle	62	distillate	509,595	dscfm	Temp=336 deg. F, Moisture=9.8%,
Nickel	2.1 E - 4	4.4 E - 4	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Phenanthrene	2.8 E - 5	13 E - 5	Simple-Cycle	63	distillate	620,710	dscfm	Temp=351 deg. F, Moisture=4.7%
Pyrene	8.6 E - 6 **	23 E - 6	Simple-Cycle	17	diesel	158,400	dscfm	Temp=987 deg. F, Moisture=5.7%,
Selenium	2.5 E - 4 **	4.3 E - 4 **	Simple-Cycle	61.5	No. 2 fuel oil	201	m3/sec	
Thallium	2.9 E - 4 **	3.8 E - 4	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Tin	4.3 E - 3 **	35. E - 3	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Vanadium	2.4 E - 2	5.1 E - 2	Simple-Cycle	61.9	No. 2 fuel oil	205	m3/sec	
Zinc	8.1 E - 1	8.2 E - 1	Simple-Cycle	61.5	No. 2 fuel oil	201	m3/sec	

\*\* Note: The EPRI PISCES Database conservatively reports "Non-Detect" analytical results as the detection level of the analytical method used. Minimum and Maximum data marked by \*\* are Non-Detect data reported at the detection level of the analytical method(s) used.



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**FILED**

**JUL 25 1985**

**JANE BURGIO**  
**Secretary of State**

**CERTIFICATE OF INCORPORATION**

**of**

**PUBLIC SERVICE ENTERPRISE GROUP  
INCORPORATED**

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**850010260**

**Certificate of Incorporation  
of  
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**

The undersigned, a corporation of the State of New Jersey, for the purpose of forming a corporation pursuant to the provisions of the New Jersey Business Corporation Act, does hereby certify as follows:

**1. NAME:**

The name of the corporation is **PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED.**

**2. PURPOSE:**

The purpose for which the corporation is organized is to engage in any activity within the purposes for which corporations may be organized under the New Jersey Business Corporation Act, as from time to time amended or supplemented.

**3. STOCK:**

The aggregate number of shares which the corporation shall have authority to issue is 150,000,000 shares of Common Stock, without par value.

**4. PRE-EMPTIVE RIGHTS:**

No holder of shares of stock of any class of the corporation shall be entitled as of right to subscribe for, purchase, or receive any part of any new or additional issue of any class of stock of the corporation or any bonds, debentures, or other securities convertible into any such stock; provided, however, that the corporation shall not issue for cash any shares of Common Stock or securities convertible into Common Stock, in any manner other than by a public offering by competitive bidding or by an offering to or through underwriters or investment bankers who shall have agreed to make a public offering thereof promptly or by a plan for the benefit of employees of the corporation or any subsidiary thereof, without first offering the same to the holders of Common Stock then outstanding.

**5. RESTRICTION ON DIVIDENDS:**

No dividends shall be paid on any shares of any class of stock of the corporation except out of its earned surplus.

**6. CUMULATIVE VOTING:**

At all elections of directors each holder of Common Stock shall be entitled to as many votes as shall equal the number of his shares of Common Stock multiplied by the number of directors to be elected, and the stockholder may cast all of such votes for a single director or may distribute them among the number to be voted for, or any two or more of them as he may see fit.

**7. CERTAIN VOTING REQUIREMENTS:**

Except as otherwise required by law or this Certificate of Incorporation, action by the stockholders to adopt a proposed amendment to this Certificate of Incorporation or to approve a proposed plan of merger or consolidation involving the corporation or to approve a proposed sale, lease, exchange or other disposition of all, or substantially all, the assets of the corporation, if not in the usual and regular course of its business as conducted by it, or to dissolve, may be taken by the affirmative vote of a majority of the votes cast by the holders of stock of the corporation entitled to vote thereon and, in addition, if any class or series of stock is entitled to vote thereon as a class, by the affirmative vote of a majority of the votes cast in each class vote.

**8. INDEMNIFICATION OF DIRECTORS, OFFICERS AND EMPLOYEES:**

The corporation shall indemnify to the full extent from time to time permitted by law any person made, or threatened to be made, a party to any pending, threatened or completed civil, criminal, administrative or arbitral action, suit or proceeding and any appeal therein (and any inquiry or investigation which could lead to such action, suit or proceeding) by reason of the fact that he is or was a director, officer or employee of the corporation or serves or served any other enterprise as a director, officer or employee at the request of the corporation. Such right of indemnification shall inure to the benefit of the legal representative of any such person.

**9. CHANGES IN NUMBER OF DIRECTORS; FILLING NEWLY CREATED DIRECTORSHIP:**

The number of directors at any time may be increased or (in the event of an existing vacancy) diminished by vote of the Board of Directors, and in case of any such increase the Board of Directors shall have power to elect each such additional director to hold office until the next succeeding annual meeting of stockholders and until his successor shall have been elected and qualified.

**10. REMOVAL AND SUSPENSION OF DIRECTORS:**

The Board of Directors, by the affirmative vote of a majority of the directors in office, may remove a director or directors for cause where, in the judgment of such majority, the continuation of the director or directors in office would be harmful to the corporation and may suspend the director or directors for a reasonable period pending final determination that cause exists for such removal.

**11. QUORUM OF STOCKHOLDERS:**

At any meeting of the stockholders of the corporation, the holders of stock entitled to cast a majority of the votes at the meeting, present in person or represented by proxy, shall constitute a quorum of the stockholders for all purposes unless the representation of a larger number shall be required by law, and in that case the representation of the number so required shall constitute a quorum.

If the holders of the amount of stock necessary to constitute a quorum shall fail to attend in person or by proxy at the time and place fixed for any meeting of stockholders, the meeting may be adjourned from time to time by the vote of a majority of the votes cast by the holders of stock present in person or represented by proxy at such meeting, without notice other than by announcement at the meeting, and at any such adjourned meeting held more than one week after such time the holders of stock entitled to cast 40% of the votes at such meeting, present in person or represented by proxy, shall constitute a quorum of the stockholders for all purposes unless the representation of a larger number shall be required by law, and in that case the representation of the number so required shall constitute a quorum. At any such adjourned meeting, whenever held, at which a quorum shall be present, any business may be transacted which might have been transacted at the meeting as originally called.

**12. REGISTERED OFFICE AND AGENT:**

The address of the corporation's initial registered office is 80 Park Plaza, Newark, New Jersey 07101, and the name of the corporation's initial registered agent at such address is Robert S. Smith.

**13. DIRECTORS:**

The number of directors constituting the first Board of Directors of the corporation is four, and the names and addresses of the persons who are to serve as such directors are as follows:

Everett L. Morris	80 Park Plaza, Newark, New Jersey 07101
Frederick W. Schneider	80 Park Plaza, Newark, New Jersey 07101
R. Edwin Selover	80 Park Plaza, Newark, New Jersey 07101
Harold W. Sonn	80 Park Plaza, Newark, New Jersey 07101

**14. INCORPORATOR:**

The name and address of the incorporator is Public Service Electric and Gas Company, 80 Park Plaza, Newark, New Jersey 07101.

IN WITNESS WHEREOF, the undersigned, the incorporator of the above-named corporation, has caused this Certificate of Incorporation to be executed this 25th day of July, 1985.

PUBLIC SERVICE ELECTRIC  
AND GAS COMPANY

By /s/ HAROLD W. SONN  
(Harold W. Sonn)  
*Chairman of the Board,  
President and  
Chief Executive Officer*

**Certificate of Amendment  
FILED  
APRIL 23, 1987  
JANE BURGIO  
Secretary of State**

**Certificate of Amendment  
of  
Certificate of Incorporation  
of  
PUBLIC SERVICE  
ENTERPRISE GROUP INCORPORATED**

**Increasing authorized Common Stock from 150,000,000 shares to 500,000,000 shares, authorizing a new class of 50,000,000 shares of Preferred Stock, requiring 80% shareholder approval of certain mergers and other business combinations under certain conditions, classifying the Board of Directors into three classes of Directors, requiring 80% shareholder approval for certain By-Law amendments and limiting personal liability of directors and officers.**

**Effective April 23, 1987**

**850010265**

**Certificate of Amendment  
of  
Certificate of Incorporation  
of  
Public Service Enterprise Group Incorporated**

Public Service Enterprise Group Incorporated, a New Jersey corporation, does hereby certify, pursuant to subsection 14A:9-4(3) of the New Jersey Business Corporation Act, as amended, that:

1. The name of this corporation is "Public Service Enterprise Group Incorporated".

2. The date of adoption of the amendments set forth in this Certificate of Amendment by the stockholders was April 21, 1987.

3. The number of shares entitled to vote on the amendments set forth in this Certificate of Amendment was 134,981,136 shares of Common Stock.

4. (a) Article 3 of the Certificate of Incorporation dated July 25, 1985 of this corporation has been amended, by vote of the stockholders of this corporation, so as to increase the authorized Common Stock from 150,000,000 shares to 500,000,000 shares.

(b) The number of votes cast by the holders of Common Stock for and against said amendment were as follows:

For	Against
94,590,268	10,575,620

5. (a) Article 3 of the Certificate of Incorporation dated July 25, 1985 of this corporation has been further amended, by vote of the stockholders of this corporation, to authorize a new class of 50,000,000 shares of Preferred Stock.

(b) The number of votes cast by the holders of Common Stock for and against said amendment were as follows:

For	Against
78,616,663	18,109,174

6. (a) Article 8 of the Certificate of Incorporation dated July 25, 1985 of this corporation has been amended, by vote of the stockholders of this corporation, so as to add a provision to limit the personal liability of directors and officers.

(b) The number of votes cast by the holders of Common Stock for and against said amendment were as follows:

For	Against
94,974,819	8,797,560

7. (a) The Certificate of Incorporation dated July 25, 1985 of this corporation has been amended by adding new Articles 9, 10 and 11 to (i) require 80% shareholder approval of certain mergers and other business combinations unless certain fair price voting and procedural requirements are met or the transaction is approved by a majority of disinterested directors, (ii) classify the Board of Directors, (iii) require 80% shareholder approval for certain by-law amendments, and (iv) make related changes; and as a result of said amendments, existing Articles 9 and 10 of the Certificate of Incorporation dated July 25, 1985 of this corporation have been deleted and existing Articles 11 through 14 of said Certificate of Incorporation have been renumbered as Articles 12 through 15.

(b) The number of votes cast by the holders of Common Stock for and against said amendments were as follows:

For	Against
75,011,767	22,322,471

8. The amendments of the Certificate of Incorporation dated July 25, 1985 of this corporation, which were adopted by the stockholders of this corporation on April 21, 1987 as aforesaid, are as follows:

(a) Article 3 was amended to read as follows:

“ 3. STOCK:

SECTION 1. Capital Stock. The corporation shall have the authority to issue 500,000,000 shares of Common Stock, without par value, and 50,000,000 shares of Preferred Stock, without par value.

SECTION 2. Preferred Stock. The Board of Directors shall have authority to issue the shares of Preferred Stock from time to time on such terms as it may determine, and to divide the Preferred Stock into one or more classes or series and in connection with the creation of any such class or series to fix, by resolution or resolutions providing for the issue thereof, the designation, the number of shares, and the relative rights, preferences and limitations thereof, to the full extent now or hereafter permitted by law. ”

(b) Article 8 was amended to read as follows:

“ 8. INDEMNIFICATION: LIMITATION OF LIABILITY:

SECTION 1. Indemnification. The corporation shall indemnify to the full extent from time to time permitted by law any person made, or threatened to be made, a party to any pending, threatened or completed civil, criminal, administrative or arbitral action, suit or proceeding and any appeal therein (and any inquiry or investigation which could lead to such action, suit or proceeding) by reason of the fact that he is or was a director, officer or employee of the corporation or serves or served any other enterprise as a director, officer or employee at the request of the corporation. Such right of indemnification shall inure to the benefit of the legal representative of any such person.

**SECTION 2. Limitation of Liability.** To the full extent from time to time permitted by law, directors and officers of the corporation shall not be personally liable to the corporation or its shareholders for damages for breach of any duty owed to the corporation or its shareholders. No amendment or repeal of this provision shall adversely affect any right or protection of a director or officer of the corporation existing at the time of such amendment or repeal. "

(c) New Articles 9, 10 and 11 were added, existing Articles 9 and 10 were deleted, and existing Articles 11 through 14 were renumbered as Articles 12 through 15. New Articles 9, 10 and 11 read as follows:

**" 9. CERTAIN BUSINESS COMBINATIONS:**

**SECTION 1. Vote Required for Certain Business Combinations.** In addition to any affirmative vote required by law and except as otherwise expressly provided in Section 2 of this Article 9:

(a) any merger or consolidation of the corporation or any Subsidiary (hereinafter defined) with (i) any Interested Shareholder (hereinafter defined) or (ii) any other corporation (whether or not itself an Interested Shareholder) which is, or after such merger or consolidation would be, an Affiliate (hereinafter defined) of an Interested Shareholder; or

(b) any sale, lease, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions) to or with any Interested Shareholder or any Affiliate of any Interested Shareholder of any assets of the corporation or any Subsidiary having an aggregate Fair Market Value (hereinafter defined) of \$25,000,000 or more; or

(c) the issuance or transfer by the corporation or any Subsidiary (in one transaction or a series of transactions) of any securities of the corporation or any Subsidiary to any Interested Shareholder or Affiliate of any Interested Shareholder in exchange for cash, securities or other property (or a combination thereof) having an aggregate Fair Market Value of \$25,000,000 or more; or

(d) the adoption of any plan or proposal for the liquidation or dissolution of the corporation proposed by or on behalf of any Interested Shareholder or any Affiliate of any Interested Shareholder; or

(e) any reclassification of securities (including any reverse stock split), recapitalization of the corporation, any merger or consolidation of the corporation with any of its Subsidiaries or any other transaction (whether or not with or into or otherwise involving an Interested Shareholder) which has the effect, directly or indirectly, of increasing the proportionate share of the outstanding shares of any class of equity or convertible securities of the corporation or any Subsidiary which is directly or indirectly owned by any Interested Shareholder or any Affiliate of any Interested Shareholder;

shall require prior approval by the affirmative vote of 80% of the votes which the holders of the then outstanding shares of capital stock of the corporation are entitled to vote in the election of directors (the "Voting Stock"), voting together as a single class (each share of the Voting Stock having a number of votes duly fixed by the Board of Directors pursuant to Article 3 of the Certificate of Incorporation or provided by the By-Laws). Such affirmative vote shall be required notwithstanding the fact that no vote may be required, or that a lesser percentage may be specified, by law or in any agreement with any national securities exchange or otherwise. The term "Business Combination" as used in this Article 9 shall mean any transaction which is referred to in any one or more of paragraphs (a) through (e) of this Section 1.

**SECTION 2. Exceptions to 80% Vote.** The provisions of Section 1 of this Article 9 shall not be applicable to any particular Business Combination (and such Business Combination shall require only such affirmative vote which may be required by law or otherwise) if all of the conditions specified in either of the following paragraphs (a) or (b) are met:

(a) The Business Combination shall have been approved by majority vote of the Disinterested Directors (hereinafter defined).

(b) All of the following conditions shall have been met:

(i) The aggregate amount of the cash and the Fair Market Value, as of the date of the consummation of the Business Combination, of consideration other than cash to be received per share by holders of Common Stock in such Business Combination shall be at least equal to the higher of:

(1) if applicable, the highest per share price (including any brokerage commissions, transfer taxes and soliciting dealers' fees) paid by the Interested Shareholder for any shares of Common Stock acquired by it (x) within the two-year period immediately prior to the first public announcement of the proposal of the Business Combination (the "Announcement Date") or (y) in the transaction in which it became an Interested Shareholder, whichever is higher; or

(2) the Fair Market Value per share of Common Stock on the Announcement Date or on the date (the "Determination Date") on which the Interested Shareholder became an Interested Shareholder, whichever is higher.

(ii) The aggregate amount of the cash and the Fair Market Value, as of the date of the consummation of the Business Combination, of consideration other than cash to be received per share by holders of shares of any class or series of outstanding Voting Stock other than Common Stock shall be at least equal to the highest of the following (it being intended that the requirements of this paragraph (b)(ii) shall be

met with respect to every such class or series whether or not the Interested Shareholder has previously acquired any shares thereof):

(1) if applicable, the highest per share price (including any brokerage commissions, transfer taxes and soliciting dealers' fees) paid by the Interested Shareholder for any shares of such class or series acquired by it (x) within the two-year period immediately prior to the Announcement Date or (y) in the transaction in which it became an Interested Shareholder, whichever is higher; or

(2) if applicable, the highest preferential amount per share to which the holders of shares of such class or series are entitled in the event of any voluntary or involuntary liquidation, dissolution or winding up of the corporation; or

(3) the Fair Market Value per share of such class or series on the Announcement Date or on the Determination Date, whichever is higher.

(iii) The consideration to be received by holders of a particular class or series of outstanding Voting Stock (including Common Stock) shall be in cash or in the same form as the Interested Shareholder has previously paid for shares of such class or series of Voting Stock. If the Interested Shareholder has paid for shares of any class or series of Voting Stock with varying forms of considerations, the form of consideration for such class or series shall be either cash or the form used to acquire the largest number of shares of such class or series previously acquired by it. The price determined in accordance with paragraphs (b)(i) and (b)(ii) of this Section 2 shall be subject to appropriate adjustment in the event of any stock dividend, stock split, combination of shares or similar event.

(iv) After such Interested Shareholder has become an Interested Shareholder and prior to the consummation of such Business Combination: (1) except as approved by a majority of the Disinterested Directors, there shall have been no failure to declare and pay at the regular date therefor any dividends (whether or not cumulative) on any outstanding series of Preferred Stock; (2) there shall have been (x) no reduction in the annual rate of dividends paid on the Common Stock (except as necessary to reflect any subdivisions of the Common Stock), except as approved by a majority of the Disinterested Directors, and (y) an increase in such annual rate of dividends as necessary to reflect any reclassification (including any reverse stock split), recapitalization, reorganization or any similar transaction which has the effect of reducing the number of outstanding shares of Common Stock, unless the failure to so increase such annual rate is approved by a majority of the Disinterested Directors; and (3) such Interested Shareholder shall have not become the beneficial owner of any additional shares of Voting Stock except as part of the transaction which results in such Interested Shareholder becoming an Interested Shareholder.

(v) After such Interested Shareholder has become an Interested Shareholder, such Interested Shareholder shall not have received the benefit, directly or indirectly (except proportionately as a shareholder), of any loans, advances, guarantees, pledges or other financial assistance, or any tax credits or other tax advantages, provided by the corporation, whether in anticipation of or in connection with such Business Combination or otherwise.

(vi) A proxy or information statement describing the proposed Business Combination and complying with the requirements of the Securities Exchange Act of 1934 and the rules and regulations thereunder (or any subsequent provisions replacing such act, rules or regulations) shall be mailed to shareholders of the corporation at least 30 days prior to the consummation of such Business Combination (whether or not such proxy or information statement is required to be mailed pursuant to such act, rules and regulations or subsequent provisions).

**SECTION 3. Certain Definitions. For the purposes of this Article 9:**

(a) "Person" shall mean any individual, firm, corporation or other entity.

(b) "Interested Shareholder" shall mean any person (other than the corporation or any Subsidiary) who or which:

(i) is the beneficial owner, directly or indirectly, of shares having 10% or more of the votes of the then outstanding Voting Stock; or

(ii) is an Affiliate of the corporation and at any time within the two-year period immediately prior to the date in question was the beneficial owner, directly or indirectly, of shares having 10% or more of the votes of the then outstanding Voting Stock; or

(iii) is an assignee of or has otherwise succeeded to any shares of Voting Stock which were at any time within the two-year period immediately prior to the date in question beneficially owned by any Interested Shareholder, if such assignment or succession shall have occurred in the course of a transaction or series of transactions not involving a public offering within the meaning of the Securities Act of 1933.

(c) A person shall be a "beneficial owner" of any Voting Stock:

(i) which such person, or any of its Affiliates or Associates (as hereinafter defined), beneficially owns, directly or indirectly; or

(ii) which such person, or any of its Affiliates or Associates, has (1) the right to acquire (whether such right is exercisable immediately or only after the passage of time) pursuant to any agreement, arrangement or understanding or upon the exercise of conversion rights, exchange rights, warrants or options or otherwise, or (2) the right to vote pursuant to any agreement, arrangement or understanding; or

(iii) which is beneficially owned, directly or indirectly, by any other person with which such person or any of its Affiliates or Associates has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting or disposing of any shares of Voting Stock.

For the purposes of determining whether a person is an Interested Shareholder, the number of shares of Voting Stock deemed to be outstanding shall include shares deemed owned through application of this paragraph (c) of Section 3 but shall not include any other shares of Voting Stock which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, warrants or options or otherwise.

(d) "Affiliate" or "Associate" shall have the respective meanings given for such terms in Rule 12b-2 of the General Rules and Regulations under the Securities Exchange Act of 1934, as in effect on January 1, 1987.

(e) "Subsidiary" shall mean any corporation of which a majority of the voting shares is owned, directly or indirectly, by the corporation.

(f) "Disinterested Director" shall mean any member of the Board of Directors of the corporation who is not an Affiliate, Associate or representative of the Interested Shareholder and was a member of the Board of Directors prior to the time that the Interested Shareholder became an Interested Shareholder, and any successor of a Disinterested Director who is not an Affiliate, Associate or representative of the Interested Shareholder and was recommended or elected to succeed a Disinterested Director by a majority of Disinterested Directors then on the Board of Directors.

(g) "Fair Market Value" shall mean:

(i) in the case of stock, the highest closing sale price during the 30-day period immediately preceding the date in question on the Composite Tape for New York Stock Exchange-Listed Stocks, or, if such stock is not quoted on the Composite Tape, on the New York Stock Exchange, or, if such stock is not listed on such exchange, on the principal United States securities exchange registered under the Securities Exchange Act of 1934 on which such stock is listed, or, if such stock is not listed on any such exchange, the highest closing bid quotation with respect to a share of such stock during the 30-day

period preceding the date in question on the National Association of Securities Dealers, Inc. Automated Quotations System or any system then in use, or if no such quotations are available, the fair market value on the date in question as determined by a majority of the Disinterested Directors in good faith; or

(ii) in the case of property other than stock, the fair market value of such property on the date in question as determined by a majority of the Disinterested Directors in good faith.

(h) In the event of any Business Combination in which the corporation survives, the phrase "consideration other than cash to be received" as used in paragraphs (b)(i) and (ii) of Section 2 of this Article 9 shall include the shares of Common Stock and/or the shares of any other class of outstanding Voting Stock retained by the holders of such shares.

**SECTION 4. Powers of the Board of Directors.** The Board of Directors shall have the power and duty, by majority vote of the Disinterested Directors, to determine for the purposes of this Article 9, on the basis of information known to them after reasonable inquiry, (a) whether a person is an Interested Shareholder, (b) the number of shares of Voting Stock beneficially owned by any person, (c) whether a person is an Affiliate or Associate of another, and (d) whether the assets which are the subject of any Business Combination have, or the consideration to be received for the issuance or transfer of securities by the corporation or any Subsidiary in any Business Combination has, an aggregate Fair Market Value of \$25,000,000 or more. A majority of the Disinterested Directors shall also have the power to interpret all of the other terms and provisions of this Article 9 and to make any other factual determinations in regard to the applicability of this Article 9. Any interpretations or determination made in good faith by majority vote of the Disinterested Directors with regard to application of this Article 9 on the basis of such information as was then available for such purpose shall be conclusive and binding on the corporation and on all of its shareholders, including any Interested Shareholder.

**SECTION 5. No Effect on Fiduciary Obligations of Interested Shareholders.** Nothing contained in this Article 9 shall be construed to relieve any Interested Shareholder from any fiduciary obligations imposed by law.

**SECTION 6. Severability.** In the event any provision (or part thereof) of this Article 9 should be determined to be invalid, prohibited or unenforceable for any reason, the remaining provisions, and parts thereof, shall remain in full force and effect and enforceable against the corporation and its shareholders, including any Interested Shareholder, to the fullest extent permitted by law.

**SECTION 7. Amendment.** Notwithstanding any other provisions of this Certificate of Incorporation, the By-Laws of the corporation or applicable law, the affirmative vote of 80% of the votes of the then outstanding Voting Stock, voting together as a single class, shall be required (a) to amend, modify or repeal this Article 9, (b) adopt any provision to this Certificate of Incorporation or By-Laws which is inconsistent with this Article 9, or (c) prior to the fixing by the

Board of Directors of any right or preference of any series of Preferred Stock which is inconsistent with the provisions of this Article 9."

**" 10. BOARD OF DIRECTORS:**

**SECTION 1. Number, election and terms.** Except as otherwise fixed by or pursuant to the provisions of Article 3 hereof relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect additional directors under specified circumstances, the number of the directors of the corporation shall be fixed from time to time by or pursuant to the By-Laws of the corporation. The directors, other than those who may be elected by the holders of any class of series of stock having a preference over the Common Stock as to dividends or upon liquidation, shall be classified, with respect to the time for which they severally hold office, into three classes, as nearly equal in number as possible, as shall be provided in the manner specified in the By-Laws of the corporation, one class to be originally elected for a term expiring at the annual meeting of stockholders to be held in 1988, another class to be originally elected for a term expiring at the annual meeting of stockholders to be held in 1989, and another class to be originally elected for a term expiring at the annual meeting of stockholders to be held in 1990, with the directors in each class to hold office until their respective successors are elected and qualified. At each annual meeting of the stockholders of the corporation, the successors of the class of directors whose term expires at that meeting shall be elected to hold office for a term expiring at the annual meeting of stockholders held in the third year following the year of their election and until their respective successors are elected and qualified.

**SECTION 2. Stockholder nomination of director candidates.** Advance notice of shareholder nominations for the election of directors shall be given in the manner provided in the By-Laws of the corporation.

**SECTION 3. Newly created directorships and vacancies.** Except as otherwise provided for or fixed by or pursuant to the provisions of Article 3 hereof relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, newly created directorships resulting from any increase in the number of directors and any vacancies on the Board of Directors resulting from death, resignation, disqualification, removal or other cause shall be filled by the affirmative vote of a majority of the remaining directors then in office, even though less than a quorum of the Board of Directors. Any director elected in accordance with the preceding sentence shall hold office until the next succeeding annual meeting of shareholders and until such director's successor, who shall be elected for the remainder of the full term of the class of directors in which the new directorship was created or the vacancy occurred, shall have been elected and qualified. No decrease in the number of directors constituting the Board of Directors shall shorten the term of any incumbent director.

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**SECTION 4. Removal and Suspension.** Subject to the rights of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, any director may be removed from office without cause only by the affirmative vote of the holders of 80% of the combined voting power of the then outstanding shares of stock entitled to vote generally in the election of directors, voting together as a single class. The Board of Directors, by the affirmative vote of a majority of the directors in office, may remove a director or directors for cause where, in the judgment of such majority, the continuation of the director or directors in office would be harmful to the corporation and may suspend the director or directors for a reasonable period pending final determination that cause exists for such removal.

**SECTION 5. Amendment, repeal, etc.** Notwithstanding anything in this Certificate of Incorporation to the contrary, the affirmative vote of the holders of at least 80% of the voting power of all shares of the corporation entitled to vote generally in the election of directors, voting together as a single class, shall be required to alter, amend, adopt any provision inconsistent with or repeal this Article 10."

**" 11. BY-LAW AMENDMENTS:**

The Board of Directors shall have power to make, alter, amend and repeal the By-Laws of the corporation (except so far as the By-Laws of the corporation adopted by the shareholders shall otherwise provide). Any By-Laws made by the Directors under the powers conferred hereby may be altered, amended or repealed by the directors or by the shareholders. Notwithstanding the foregoing and anything contained in this Certificate of Incorporation to the contrary, Article I, Section 1; Article IX, Section 9; and Article XVI of the By-Laws shall not be altered, amended or repealed and no provision inconsistent therewith shall be adopted without the affirmative vote of the holders of at least 80% of the voting power of all the shares of the corporation entitled to vote generally in the election of directors, voting together as a single class. Notwithstanding anything contained in this Certificate of Incorporation to the contrary, the affirmative vote of the holders of at least 80% of the voting power of all the shares of the corporation entitled to vote generally in the election of directors, voting together as a single class, shall be required to alter, amend, or adopt any provision inconsistent with or repeal this Article 11."

**IN WITNESS WHEREOF,** said Public Service Enterprise Group Incorporated has made this Certificate this 23rd day of April, 1987.

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**

**By E. JAMES FERLAND**

**E. James Ferland**

**Chairman of the Board, President  
and Chief Executive Officer**

**Attest:**

**D. S. POCIUS**

**Assistant Secretary**

**(Corporate Seal)**

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
WASHINGTON, D.C. 20549**

**FORM 10-K**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF  
THE SECURITIES EXCHANGE ACT OF 1934  
For the fiscal year ended December 31, 1995**

**Commission file number 1-9120**

**Public Service Enterprise Group Incorporated**

(Exact name of registrant as specified in its charter)

**New Jersey**  
(State or other jurisdiction of  
incorporation or organization)

**22-2625848**  
(I.R.S. Employer  
Identification No.)

**80 Park Plaza, P.O. Box 1171**  
**Newark, New Jersey**  
(Address of principal executive offices)

**07101-1171**  
(Zip Code)

**Registrant's telephone number, including area code: 201 430-7000**

**Securities registered pursuant to Section 12(b) of the Act:**

**Title of Each Class**  
Common Stock without par value

**Name of Each Exchange  
on Which Registered**  
New York Stock Exchange  
Philadelphia Stock Exchange

**Commission file number 1-973**

**Public Service Electric and Gas Company**

(Exact name of registrant as specified in its charter)

**New Jersey**  
(State or other jurisdiction of  
incorporation or organization)

**22-1212800**  
(I.R.S. Employer  
Identification No.)

**80 Park Plaza, P.O. Box 570**  
**Newark, New Jersey**  
(Address of principal executive offices)

**07101-0570**  
(Zip Code)

**Registrant's telephone number, including area code: 201 430-7000**

**DOCUMENTS INCORPORATED BY REFERENCE**

**Part of Form 10-K**

III

**Documents Incorporated by Reference**

Portions of the definitive Proxy Statement for the Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated to be held April 16, 1996, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 1, 1996, as specified herein.

## Securities registered pursuant to Section 12(b) of the Act:

<u>Title of Each Class</u>	<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
Cumulative Preferred Stock \$100 par value Series:	First and Refunding Mortgage Bonds Series Due:	
4.08%	8¾% Z 1999	New York Stock Exchange
4.18%	9¼% BB 2005	
4.30%	9¼% CC 2021	
5.05%	8⅞% DD 2003	
5.28%	8¾% EE 2021	
5.97%	7⅞% FF 2001	
6.80%	7¼% GG 1997	
7.40%	8¾% HH 2022	
7.44%	7⅞% II 2000	
7.52%	6⅞% KK 1997	
7.70%	8½% LL 2022	
	6⅞% MM 2003	
	6 % NN 1998	
Cumulative Preferred Stock \$25 par value Series:	7½% OO 2023	
	6½% PP 2004	
6.75%	6 % QQ 2000	
	6½% RR 2002	
	7 % SS 2024	
	7⅞% TT 2014	
	6¾% UU 2006	
	6¾% VV 2016	
	6¼% WW 2007	
	8 % 2037	
	5 % 2037	
Monthly Income Preferred Securities		
\$25 par Value Series:		
9.375%		
8.00%		

## Securities registered pursuant to Section 12(g) of the Act:

<u>Registrant</u>	<u>Title of Class</u>
Public Service Enterprise Group Incorporated	None
Public Service Electric and Gas Company	6.92% Cumulative Preferred Stock \$100 par value Medium-Term Notes, Series A

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of January 31, 1996 was \$7,642,239,750 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Enterprise's sole class of common stock, as of the latest practicable date, was as follows:

<u>Class</u>	<u>Outstanding at January 31, 1996</u>
Common Stock, without par value	244,697,930

As of January 31, 1996, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated (Enterprise).

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## GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations or acronyms that are found in this report:

<u>Term</u>	<u>Meaning</u>
ACO .....	Administrative Consent Order
AFDC .....	Allowance for Funds used During Construction
Alternative Rate Plan .....	New Jersey Partners in Power Plan
AMT .....	Alternative Minimum Tax
BCFE .....	Billion Cubic Feet Equivalent
Bonds .....	First and Refunding Mortgage Bonds
BPU .....	New Jersey Board of Public Utilities
BTA .....	Best Technology Available
BWR .....	Boiling Water Reactor
CAA .....	Federal Clean Air Act
Capital .....	PSEG Capital Corporation
CEA .....	Community Energy Alternatives Incorporated
CEA USA .....	CEA USA, Inc.
CEA New Jersey .....	CEA New Jersey, Inc.
CERCLA .....	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980
Certificate of Need .....	Certificate of Need under the NJNAA
CORP .....	New Jersey Commission on Radiation Protection
DGW .....	Discharge to Ground Water
DOE .....	United States Department of Energy
DRBC .....	Delaware River Basin Commission
DRIP .....	Enterprise's Dividend Reinvestment and Stock Purchase Plan
DSM .....	Demand Side Management
DSW .....	Discharge to Surface Water
Eagle Point .....	CEA Eagle Point, Inc.
EBIT .....	Earnings before interest and taxes
ECRA .....	New Jersey Environmental Cleanup Responsibility Act
EDC .....	Energy Development Corporation
EDHI .....	Enterprise Diversified Holdings Incorporated
EGDC .....	Enterprise Group Development Corporation
EITF .....	FASB's Emerging Issues Task Force
EMF .....	Electric and Magnetic Fields
Enterprise .....	Public Service Enterprise Group Incorporated
EPA .....	United States Environmental Protection Agency
EPAct .....	National Energy Policy Act of 1992
EPC .....	Eagle Point Cogeneration Facility
EWGs .....	Exempt Wholesale Generators
FASB .....	Financial Accounting Standards Board
Fault Act .....	New Jersey Public Utility Accident Fault Determination Act
FERC .....	Federal Energy Regulatory Commission
Fuelco .....	PSE&G Fuel Corporation
Funding .....	Enterprise Capital Funding Corporation
FWPCA .....	Federal Water Pollution Control Act
GE .....	General Electric
GEMS .....	Gloucester Environmental Management Services, Inc.
Hope Creek .....	Hope Creek Nuclear Generating Station
IPP .....	Independent Power Producers

<u>Term</u>	<u>Meaning</u>
IRP .....	Integrated Resource Plan
IRS .....	Internal Revenue Service
ISO .....	Independent System Operator
KWH .....	Kilowatthours
LEAC .....	Electric Levelized Energy Adjustment Clause
LGAC .....	Levelized Gas Adjustment Charge
LLRW .....	Low Level Radioactive Waste
LNG .....	Liquefied Natural Gas
LPG .....	Liquid Petroleum Air Gas
LTIP .....	Long-Term Incentive Plan
MAAC .....	Mid-Atlantic Area Reliability Council
MD&A .....	Management's Discussion and Analysis of Financial Condition and Results of Operations
MICP .....	Management Incentive Compensation Plan
mmbtu .....	Millions of British Thermal Units
MOA .....	Memorandum of Agreement
Mortgage .....	First and Refunding Mortgage of PSE&G
MTNs .....	Medium-Term Notes
MW .....	Megawatts
MWH .....	Megawatthours
NAAQS .....	National Ambient Air Quality Standards
NEIL .....	Nuclear Electric Insurance Limited
NJAPCC .....	New Jersey Air Pollution Control Code
NJDEP .....	New Jersey Department of Environmental Protection
NJGRT .....	New Jersey Gross Receipts and Franchise Tax
NJNAA .....	New Jersey Need Assessment Act
NJPDES .....	New Jersey Pollution Discharge Elimination System
NJWPCA .....	New Jersey Water Pollution Control Act
NML .....	Nuclear Mutual Limited
NOC .....	Nuclear Oversight Committee
NOPR .....	Notice of Proposed Rulemaking
NOV .....	Notice of Violation
NOx .....	Nitrogen Oxides
NPDES .....	National Pollutant Discharge Elimination System
NPS .....	The BPU's nuclear performance standard established for nuclear generating stations owned by New Jersey electric utilities
NRC .....	Nuclear Regulatory Commission
NUGs .....	Nonutility Generators
NWPA .....	Nuclear Waste Policy Act of 1982, as amended
OAL .....	Office of Administrative Law of the State of New Jersey
OPEB .....	Other Postretirement Benefits
OTAG .....	Ozone Transport Assessment Group
Partnership .....	Public Service Electric and Gas Capital, L.P.
Peach Bottom .....	Peach Bottom Atomic Power Station, Units 2 and 3
PECO .....	PECO Energy Inc.
PJM .....	Pennsylvania—New Jersey—Maryland Interconnection
PJP .....	PJP Landfill in Jersey City, New Jersey
POTW .....	Publicly Owned Treatment Works
PPUC .....	Pennsylvania Public Utility Commission
Price Anderson .....	Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended

<u>Term</u>	<u>Meaning</u>
PRAP .....	Proposed Remedial Action Plan
PRPs .....	Potentially Responsible Parties
PSE&G .....	Public Service Electric and Gas Company
PSCRC .....	Public Service Conservation Resources Corporation
PSRC .....	Public Service Resources Corporation
PUHCA .....	Public Utility Holding Company Act of 1935
PURPA .....	Public Utility Regulatory Policies Act of 1978
PWR .....	Pressurized Water Reactor
QFs .....	Qualifying Facilities
RAC .....	Remediation Adjustment Charge
RACT .....	Reasonable Available Control Technologies
RAR .....	Revenue Agent's Report
RCRA .....	Federal Resource Conservation and Recovery Act of 1976
Remediation Program .....	PSE&G Gas Plant Remediation Program
RI .....	Remedial Investigation
RI/FS .....	Remedial Investigation and Feasibility Study
RIPW .....	Remedial Investigation Work Plan
ROD .....	Record of Decision
Salem .....	Salem Nuclear Generating Station, Units 1 and 2
SALP .....	Systematic Assessment of Licensee Performance
SEC .....	Securities and Exchange Commission
SFAS 71 .....	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 106 .....	Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other than Pensions"
SFAS 107 .....	Statement of Financial Accounting Standards No. 107, "Disclosures About Fair Value of Financial Instruments"
SFAS 109 .....	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes"
SFAS 121 .....	Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets"
SFAS 123 .....	Statement of Financial Accounting Standards No. 123, "Accounting for Stock Based Compensation"
SIU .....	Significant Industrial Users
SNG Plant .....	Synthetic Natural Gas Plant
Spill Act .....	New Jersey Spill Compensation and Control Act
SPPP .....	Stormwater Pollution Prevention Plans
USDOT .....	United States Department of Transportation
USEC .....	United States Enrichment Corporation
USEP .....	U.S. Energy Partners
Ventures .....	Enterprise Ventures & Services
VOC .....	Volatile Organic Compound

## **PART I**

### **Item 1. Business**

#### **General**

##### **Enterprise**

Public Service Enterprise Group Incorporated (Enterprise), incorporated under the laws of the State of New Jersey with its principal executive offices located at 80 Park Plaza, Newark, New Jersey 07101, is a public utility holding company that neither owns nor operates any physical properties. Enterprise has two direct wholly-owned subsidiaries, Public Service Electric and Gas Company (PSE&G) and Enterprise Diversified Holdings Incorporated (EDHI). Enterprise's principal subsidiary, PSE&G, is an operating public utility providing electric and gas service in certain areas in the State of New Jersey. Enterprise has claimed an exemption from regulation by the Securities and Exchange Commission (SEC) as a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA), except for Section 9(a)(2) thereof which relates to the acquisition of voting securities of an electric or gas utility company. PSE&G is subject to direct regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). EDHI is the parent of Enterprise's nonutility businesses: Energy Development Corporation (EDC), an oil and gas exploration and production and marketing company; Community Energy Alternatives Incorporated (CEA), an investor in and developer and operator of cogeneration and independent power production facilities; Public Service Resources Corporation (PSRC), which makes primarily passive investments; Enterprise Group Development Corporation (EGDC), a diversified nonresidential real estate development and investment business; PSEG Capital Corporation (Capital), which provides debt financing on the basis of a minimum net worth maintenance agreement from Enterprise; and Enterprise Capital Funding Corporation (Funding), which provides privately placed debt financing on the basis of the consolidated financial position of EDHI without direct support from Enterprise. As of December 31, 1995 and 1994, PSE&G comprised 85% of Enterprise's assets. PSE&G's 1995, 1994 and 1993 revenues were 93% of Enterprise's revenues and PSE&G's earnings available to Enterprise for such years were 88%, 91% and 96%, respectively, of Enterprise's net income. Production of electricity and electric and gas distribution will continue as the principal business of Enterprise for the foreseeable future. Enterprise has announced that it intends to divest EDC in 1996. See EDHI—EDC and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

Financial information with respect to business segments of PSE&G and Enterprise is set forth in Note 15—Financial Information by Business Segments of Notes to Consolidated Financial Statements (Notes).

##### **PSE&G**

PSE&G, a New Jersey corporation with its principal executive offices at 80 Park Plaza, Newark, New Jersey 07101, is an operating public utility company engaged principally in the generation, transmission, distribution and sale of electric energy service and in the transmission, distribution and sale of gas service in New Jersey. PSE&G supplies electric and gas service in areas of New Jersey in which approximately 5,500,000 persons, about 70% of the State's population, reside. (See General—Enterprise.)

PSE&G's electric and gas service area is a corridor of approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the City of Camden in the southwest. The greater portion of this area is served with both electricity and gas, but some parts are served with electricity only and other parts with gas only. This heavily populated, commercialized and industrialized territory encompasses most of New Jersey's largest municipalities, including its six largest cities—Newark, Jersey City, Paterson, Elizabeth, Trenton and Camden—in addition to approximately 300 suburban and rural communities. It contains a diversified mix of commerce and industry, including major facilities of many corporations of national prominence.

Under the general laws of New Jersey, PSE&G has the right to use the public highways, streets and alleys in New Jersey for erecting, laying and maintaining poles, conduits and wires necessary for its electric operations.

PSE&G must, however, first obtain the consent in writing of the owners of the soil for the purpose of erecting poles. In incorporated cities and towns, PSE&G must obtain from the municipality a designation of the streets in which the poles are to be placed and the manner of placing them. PSE&G's rights are also subject to regulation by municipal authorities with respect to street openings and the use of streets for erecting poles in incorporated cities and towns.

PSE&G, by virtue of a special charter granted by the State of New Jersey to one of its predecessors, has the right to use the roads, streets, highways and public grounds in New Jersey for pipes and conduits for distributing gas.

PSE&G believes that it has all the franchises (including consents) necessary for its electric and gas operations in the territory it serves. Such franchises are non-exclusive.

For discussion of the significant changes which PSE&G's electric and gas utility businesses have been and are undergoing, see *Competition and Regulation*.

## **Industry Issues**

Enterprise and PSE&G are affected by many issues that are common to the electric and gas industries, such as: deregulation and the unbundling of energy supplies and services; an increasingly competitive energy marketplace, sales retention and growth potential in a mature service territory and a need to contain costs (see *Competition, Regulation and MD&A—Competition*); ability to operate nuclear plants in a cost effective way (see *PSE&G—Nuclear Operations*); ability to obtain adequate and timely rate relief, cost recovery, including the potential impact of stranded assets, and other necessary regulatory approvals (see *PSE&G—Rate Matters; Regulation and Item 7. MD&A—Competition*); costs of construction (see *Construction and Capital Requirements*); operating restrictions, increased costs and construction delays attributable to environmental regulations (see *Environmental Controls*); controversies regarding electric and magnetic fields (EMF) (see *Environmental Controls*); nuclear decommissioning and the availability of reprocessing and storage facilities for spent nuclear fuel (see *Electric Fuel Supply and Disposal*); and credit market concerns with these issues.

## **Competition**

### **Overview**

The energy utility industry is in transition. Changes in Federal and state law and regulation are encouraging new entrants to the traditional markets of electric and gas utilities. New technologies are creating opportunities for new energy services. Customers, more aware and sophisticated about their choices and dissatisfied with prices and the often limited range of options available from the local utility, are increasingly turning elsewhere for energy supplies and services. As a consequence of competition, the traditional utility structure—consisting of a vertically integrated system and functioning as a natural monopoly—is being dramatically altered. Further, PSE&G's ability to meet competition and change prices to meet customer's needs is impacted by state regulation, including the historic utility mandate to serve all customers. (See *MD&A—Competition*.) For a discussion of PSE&G's alternative plan of rate regulation, "New Jersey Partners in Power" (Alternative Rate Plan) as a response to these demands, see *MD&A and Note 2—Rate Matters of Notes*.

Non health and safety related Federal energy laws and regulations are designed to make more efficient use of all energy, introduce price competition, encourage the use of nonconventional energy sources and limit oil imports by increasing production of domestic energy resources. Among other things, these actions (1) encourage development of alternative energy generation, (2) require wheeling of power for wholesale transactions, (3) require state regulatory authorities to consider certain standards on rate design and certain other utility practices, (4) encourage conservation of energy through certain financial incentives, including incentives by individual utilities to customers to help them to conserve energy and (5) deregulate prices on natural gas.

Also, Federal and State laws designed to reduce air and water pollution and control hazardous substances have had the effect of increasing the costs of operation and replacement of existing utility plants and other facilities. (See Environmental Controls.)

Competition from nonutility generators (NUGs), such as cogenerators, independent power producers (IPP) and exempt wholesale generators (EWGs), as permitted by the Public Utility Regulatory Policies Act of 1978 (PURPA) and the National Energy Policy Act of 1992 (EPAct), continues to impact PSE&G. As a result of changes brought about by EPAct, along with proposals in some states to authorize retail wheeling, discussed below, electric customers and suppliers, including PSE&G and its customers, have increased opportunities for purchase and sale of electricity from and to sellers and buyers outside of traditional franchised territories. Retention of existing customers and potential sales growth will depend upon the ability of PSE&G to contain costs, meet customer expectations and respond to changing economic conditions and energy regulation. As a result of such competitive forces, Enterprise Ventures & Services Corporation (Ventures) has been established as a subsidiary of PSE&G to develop and market new energy-related products and services beyond traditional geographic and/or industry boundaries. Competition may also adversely impact upon the economics of certain regulatory-created incentives, such as Demand Side Management (DSM) and conservation. For additional information, including a discussion of the potential effects of competition upon rates, cost recovery and assets, see MD&A—Competition. For information relating to the Alternative Rate Plan see MD&A and Note 1—Organization and Summary of Significant Accounting Policies, Note 2—Rate Matters and Note 5—Deferred Items of Notes.

### Electric

In the electric utility industry, competitive pressures began with the enactment of PURPA. This law, together with subsequent changes in Federal regulation, has increasingly opened the electric utility industry to competition. PURPA created a class of generating facilities exempt from Federal and State public utility regulation—cogeneration and small power producers known as “qualifying facilities” (QFs)—and created an instant market for them by requiring regulated utilities to purchase their excess power production. EPAct, by facilitating the development of the wholesale power market, has led to even stronger competition. The increasing competitiveness of the electric wholesale markets, along with consideration of retail wheeling or “direct retail access” within utility franchise areas in several states, has brought to the forefront the issue of potential stranded costs within the electric utility industry (see MD&A—Competition).

EPAct provides FERC with increased authority to order “wheeling” of wholesale, but not retail, electric power on the transmission systems of electric utilities, provided that certain requirements are met. In order to facilitate the transition to increased competition in wholesale power markets made possible by EPAct, in March 1995, FERC issued a Notice of Proposed Rulemaking (NOPR) which, if adopted, would require electric utilities, including PSE&G, to provide open access to the interstate transmission network pursuant to non-discriminatory tariffs available to all wholesale sellers and buyers of electric energy. Utilities would be required to offer transmission to eligible customers comparable to the service they provide themselves and to take service under the tariffs for their own wholesale sales and purchases. Further, transmission and ancillary service components would be unbundled and, when buying or selling power, utilities would have to rely on the same network for transmission system information as their customers.

The NOPR states FERC’s general principle that utilities should be entitled to full recovery of legitimate and verifiable stranded costs at the Federal and State levels and reiterates its prior proposal that such costs be directly assigned to departing customers. The NOPR further provides that stranded costs due to retail wheeling are a state matter, while stranded costs due to wholesale wheeling, municipalization or a change from retail to wholesale customer class are within FERC’s jurisdiction. PSE&G cannot predict the impact of any regulations that may be adopted. See MD&A—Competition. For discussion of the Pennsylvania, New Jersey and Maryland Interconnection (PJM) proposal in response to the FERC NOPR, see Pennsylvania—New Jersey—Maryland Interconnection. For a discussion of PSE&G’s actions and comments related to the potential environmental impact of the NOPR, see Environmental Controls—Air Pollution Control.

EPAct also amended PUHCA to create a new category of generation owners known as EWGs, which are not subject to PUHCA regulation. EPAct permits both independent companies and utility affiliates to participate in the development of EWG projects regardless of the location and ownership of other generating resources. The transmission access provisions apply to wholesale, but not retail, "wheeling" of power, subject to FERC review. See PSE&G—Integrated Resource Plan, Construction and Capital Requirements, Financing Activities and PSE&G—Customers. For information concerning the activities of CEA, which is an owner-developer of QFs and EWGs, see EDHI—CEA.

Another key factor in determining how competition will affect PSE&G's electric business is the extent to which New Jersey public utility regulation may be modified to be reflective of these new competitive realities. The BPU presented the first phase of the New Jersey Energy Master Plan to Governor Whitman on March 8, 1995. This Phase I Plan acknowledged the need for regulatory flexibility as competition unfolds and called for legislation that would allow New Jersey utilities to propose, subject to BPU approval, alternatives to existing rate base/rate of return pricing, allow for pricing flexibility under certain standards for customers with competitive options and equalize the impact of tax policies, such as New Jersey Gross Receipts and Franchise Tax (NJGRT) which is currently assessed only on utility retail energy sales. On July 20, 1995, Governor Whitman signed into law legislation which provides utilities the flexibility to propose alternative regulatory pricing and to offer negotiated off-tariff agreements (See PSE&G—Customers). On January 16, 1996, PSE&G filed a petition with the BPU for its Alternative Rate Plan designed to fulfill the objectives of this new regulatory reform legislation. This Alternative Rate Plan represents a regulatory transition designed to provide PSE&G with the mechanisms and incentives to compete more effectively on several fronts, including the ability to develop revenue from non-regulated products and services, accelerate or modify depreciation schedules to help mitigate any potential stranded asset issue and more aggressively manage costs. For more information regarding the Alternative Rate Plan see MD&A and Note 1—Organization and Summary of Significant Accounting Policies, Note 2—Rate Matters and Note 5—Deferred Items of Notes.

On June 1, 1995, the BPU issued its Order initiating a formal Phase II proceeding to the New Jersey Energy Master Plan. This proceeding is intended to investigate and consider the future long term structure of the electric power industry in New Jersey. The proceeding will address wholesale and retail competition, ownership of generation, transmission and distribution facilities, operation of the transmission system and stranded investments. A Phase II report proposing policy restructuring is expected by March 1996. PSE&G cannot predict what impact, if any, the Phase II report will have.

## Gas

Over the last decade the natural gas industry has experienced a dramatic transformation as several FERC initiatives have subjected the industry to competitive market forces. On the interstate level, the pipeline suppliers that serve PSE&G have unbundled gas supply and service and now offer transportation services that move gas purchased from numerous natural gas producers and marketers to PSE&G's service territory.

This unbundling effort has moved to the local level and, in late 1994, the BPU approved unbundled transport tariffs for PSE&G. These tariffs allow any non-residential customer, regardless of size, to purchase its own gas, transport it to PSE&G and require PSE&G to deliver such gas to the customer's facility. To date, over 5,000 commercial and industrial customers out of a potential of 180,000 customers have decided to utilize this service. It is expected that this number will continue to grow as marketers become more active in New Jersey and encourage customers to convert from sales service. The transportation rate schedules produce the same non-fuel revenue per therm as existing sales service rate schedules. Thus, PSE&G's earnings are unaffected whether the customers remain on sales service or convert to transportation service. See Gas Operations and Supply. In meeting the challenges and opportunities presented by this unbundling of gas supply and service, Enterprise initiated a gas marketing company, U.S. Energy Partners (USEP). For more information see EDHI—PSRC.

## Construction and Capital Requirements

For information concerning investments, construction and capital requirements see MD&A, Note 6—Schedule of Consolidated Debt, Note 7—Long-Term Investments and Note 12—Commitments and Contingent Liabilities—Construction and Fuel Supplies of Notes.

## Financing Activities

For a discussion of issuance, book value and market value of Enterprise's Common Stock and external financing activities of Enterprise, PSE&G and EDHI for the year 1995, see MD&A—Liquidity and Capital Resources and Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

For a discussion of Capital and Funding, see EDHI—Capital and EDHI—Funding. For further discussion of long-term debt and short-term debt, see Note 6—Schedule of Consolidated Debt of Notes.

## Federal Income Taxes

For information regarding Federal income taxes, see Note 1—Organization and Summary of Significant Accounting Policies, Note 2—Rate Matters and Note 10—Federal Income Taxes of Notes.

## Credit Ratings

The current ratings of securities of Enterprise's subsidiaries set forth below reflect the respective views of the rating agency furnishing the same, from whom an explanation of the significance of such ratings may be obtained. There is no assurance that such ratings will continue for any given period of time or that they will not be revised downward or withdrawn entirely by such rating agencies, if, in their respective judgments, circumstances so warrant. Any such downward revision or withdrawal of any of such ratings may have an adverse effect on the market price of Enterprise's Common Stock and PSE&G's securities and serve to increase the cost of capital of PSE&G and EDHI.

	<u>Moody's</u>	<u>Standard &amp; Poor's</u>	<u>Duff &amp; Phelps</u>	<u>Fitch</u>
<b>PSE&amp;G</b>				
Mortgage Bonds .....	A3	A -	A	A -
Debenture Bonds .....	Baa1	BBB +	A -	BBB +
Preferred Stock .....	Baa1	BBB +	A -	BBB +
Commercial Paper .....	P2	A2	Duff 1	
Fuelco: Commercial Paper .....	P2	A2	Duff 1	

As a component of the ratings noted above, each rating agency issues its opinion of the credit trend or outlook for the entity being rated. For PSE&G, each of the four rating agencies currently evaluate that outlook as stable.

### EDHI

Capital: Senior Debt .....	Baa2	BBB	BBB +
Funding: Commercial Paper(A) .....	P1	A1 +	Duff 1 +

(A) Supported by commercial bank letter of credit (see MD&A—Liquidity and Capital Resources and Note 6—Schedule of Consolidated Debt—Short-Term of Notes.)

## PSE&G

### Rate Matters

For information concerning PSE&G's Alternative Rate Plan, rate matters, and environmental remediation and fuel adjustment clauses see Note 1—Organization and Summary of Significant Accounting Policies and

Note 2—Rate Matters of Notes. For information concerning PSE&G's Under (Over) recovered Electric Energy and Gas Fuel Costs, see Note 5—Deferred Items of Notes.

### Nuclear Performance Standard

The BPU has established a nuclear performance standard (NPS) for nuclear generating stations owned by New Jersey electric utilities, including the five nuclear units in which PSE&G has an ownership interest: Salem Nuclear Generating Station, Units 1 and 2 (Salem 1 and 2)—42.59%; Hope Creek Nuclear Generating Station (Hope Creek)—95%; and Peach Bottom Atomic Power Station, Units 2 and 3 (Peach Bottom 2 and 3)—42.49%. PSE&G operates Salem and Hope Creek, while Peach Bottom is operated by PECO Energy, Inc. (PECO). The following table sets forth the capacity factor in accordance with the NPS of each of PSE&G's nuclear units for the years indicated:

<u>Nuclear Units</u>	<u>1995</u>	<u>1994</u>	<u>1993</u>
Capacity Factors:			
Salem 1 .....	26%	59%	60%
Salem 2 .....	21	58	57
Hope Creek .....	76	77	95
Peach Bottom 2 .....	96	80	84
Peach Bottom 3 .....	78	98	70
Aggregate capacity factor of nuclear units .....	62	74	77

For information concerning the NPS, see Nuclear Operations and Note 12—Commitments and Contingent Liabilities of Notes.

### Customers

As of December 31, 1995, PSE&G provided service to approximately 1,900,000 electric customers and 1,500,000 gas customers. PSE&G is not dependent on a single customer or a few customers for its electric or gas sales. For the year ended December 31, 1995, PSE&G's operating revenues aggregated \$5.7 billion, of which 70% was from its electric operations and 30% from its gas operations. PSE&G's business is seasonal in that sales of electricity are higher during the summer months because of air conditioning requirements and sales of gas are greater in the winter months due to the use of gas for space-heating purposes.

These revenues were derived as follows:

	<u>Revenues</u>	
	<u>Electric</u>	<u>Gas</u>
	<u>(Millions of Dollars)</u>	
Residential .....	\$1,275	\$ 823
Commercial .....	1,854	501
Industrial .....	705	275
Transportation Service—Gas .....	—	54
Other .....	187	33
Total .....	<u>\$4,021</u>	<u>\$1,686</u>

Customers of PSE&G, as well as those of other New Jersey electric and gas utilities, pay the NJGRT which, in effect, adds approximately 13% to their bills. The NJGRT is a unit tax based on electric kilowatthour and gas therm sales. This tax differential provides an incentive to large-volume electric and gas customers to seek to obtain their energy supplies from nonutility sources not subject to NJGRT. To the extent PSE&G experiences a loss of customers seeking to avoid this cost, it could result in a significant decrease in PSE&G's revenues and earnings.

On November 17, 1995, the BPU issued an order approving a Stipulation regarding PSE&G's proposed Experimental Hourly Energy Pricing Tariff and the first service agreement thereunder with its second largest customer. Under the agreement, the tariff will result in a bill reduction for the customer of approximately \$7 million or about 27%. This reduction in revenues will be partially offset by a decrease of \$1.25 million in PSE&G's NJGRT liability. Under the agreement between the customer and PSE&G, the customer will forego an opportunity to relocate to another state and remain a PSE&G customer for ten years. On January 2, 1996, an appeal seeking to overturn the BPU's November 17, 1995 Decision and Order was filed by a third party in the Appellate Division of the Superior Court of New Jersey. PSE&G cannot predict the outcome of this matter.

PSE&G has signed each of its three existing wholesale electric customers, aggregating 40 mw of load, to 5-year full service agreements with mid-term extension options. In addition, under the terms of a previously negotiated 10-year wholesale power transaction, PSE&G receives \$12.5 million in annual revenues from an out of state electric cooperative. For further information on the impact of competition on PSE&G's customer and revenue base—See Competition and MD&A—Competition.

### **Integrated Resource Plan**

PSE&G's construction program focuses on upgrading electric and gas transmission and distribution systems and constructing new transmission and distribution facilities to serve new load.

Pursuant to its Integrated Resource Plan (IRP), PSE&G periodically reevaluates its forecasted customer load and peak growth and the sources of electric generating capacity and DSM to meet such projected growth (see Demand Side Management below). The IRP takes into account assumptions concerning future customer demand, future cost trends, especially fuel and purchased power expenses, the effectiveness of conservation and load management activities, the long-term condition of and projected additions to PSE&G's plants and capacity available from other electric utilities and nonutility suppliers. PSE&G's IRP consists principally of plant additions, power purchases through PJM and from NUGs and DSM.

### **Pennsylvania—New Jersey—Maryland Interconnection**

PSE&G is a member of the PJM which integrates the bulk power generation and transmission supply operations of 11 utilities in Pennsylvania, New Jersey, Delaware, Maryland, Virginia and the District of Columbia, and, in turn, is interconnected with other major electric utility companies in the northeastern part of the United States. The PJM is operated as one system and provides for the purchase and sale of power among members on the basis of reliability of service and operating economy. As a result, the most economical mix of generating capability available is used to meet PJM daily load requirements. PSE&G's output, as shown under Electric Fuel Supply and Disposal, reflects significant amounts of purchased power because at times it is more economical for PSE&G to purchase power from PJM and others than to produce it. As of December 31, 1995, the aggregate installed generating capacity of the PJM companies was 56,098 megawatts (MW). The all time record peak one-hour demand experienced by the PJM power pool was 48,524 MW which occurred on August 2, 1995. The 1995 peak was 2,532 MW higher than the record-setting 1994 summer peak of 45,992 MW which occurred on July 8, 1994. PSE&G's capacity obligations to the PJM system vary from year to year due to changes in system characteristics. PSE&G expects to have sufficient installed capacity to meet its obligations during the 1996-2000 period.

PJM has developed a comprehensive proposal intended to meet or exceed the goals expressed by FERC in its open access NOPR, including a number of innovations that were designed to harmonize the requirements of the NOPR with the benefits of power pooling. In this proposal, PJM intends to satisfy the NOPR's goals by building upon the foundation of PJM's power pooling operations. The member companies of PJM intend to file this proposal with FERC by May 1996 and implement a restructured pool by year-end 1996.

Under this proposal, the current members of PJM and other load-serving entities in the PJM control area will purchase regional "network" transmission rights that are intended to enable them to reliably and

economically integrate generation and load. For deliveries to retail customers, this service will remain part of the bundled rates for retail electric service, subject to state jurisdiction, but with terms and conditions comparable to the service provided for wholesale users. Because this service will cover all deliveries to loads located in the pool, generators selling power to serve pool load will not have to purchase transmission service independently. This is intended to create a regional wholesale power market in which all sellers and buyers operate on a level playing field.

Under the proposal, transmission service will be provided under a regional point-to-point transmission service tariff. This tariff will apply a uniform ratemaking methodology to all wholesale transactions involving deliveries outside the pool, including off-system sales by the current members of PJM and other load-serving entities in the pool. Accordingly, all transmission service associated with sales outside the pool will be provided on a comparable basis.

In order to meet the requirements to functionally unbundle transmission, PJM has proposed to reorganize into an independent System Operator (ISO) with responsibility for operating the bulk power system, administering the regional transmission service tariffs and managing the pool's competitive energy market. The ISO will be governed by a Board of Directors that is not controlled by the transmission-owning members of PJM or their affiliates, and its responsibilities will be set forth in contracts filed with the FERC. The ISO will contract with the various pool participants to supply control area services, administer the transmission service tariffs and be responsible for maintaining the reliable operation of the system throughout each day.

One of the key elements of PJM's restructuring proposal is the creation of an expanded regional market for energy transactions. PJM will replace the existing system of cost-based centralized dispatch with an expanded, hourly bid/price pool in which all sellers will be able to bid their energy into the pool and all load-serving entities will be able to buy energy from the pool. The energy market will "clear" in each hour at the highest bid price for energy that must be dispatched to serve load.

Further, under the proposal, PJM will retain most of the existing pool procedures for ensuring reliable electric service, but will create new contractual mechanisms to ensure participation by all entities responsible for serving load in decisions affecting reliability. Each load-serving entity that chooses to operate in the PJM control area will be required to execute an agreement to maintain adequate generation reserves and to share those reserves on a reciprocal basis. PJM will establish an enhanced regional planning process, under the supervision of the ISO, to meet Mid-Atlantic Area Reliability Council (MAAC) reliability requirements applicable to both generation and transmission. In short, all load-serving entities in the pool will be subject to the same reliability standards and will participate in decisions relating to the establishment of regional reliability requirements.

#### **Power Purchases**

A component of PSE&G's IRP consists of expected capacity additions from NUGs. These additions are projected to aggregate 46 MW and are scheduled for service by 1998. NUG projects are expected to comprise approximately 6.5% of energy resources by 2004. This availability of NUG generation will reduce the need for PSE&G to build or acquire additional generation.

PSE&G is also a party to the MAAC which provides for review and evaluation of plans for generation and transmission facilities and other matters relevant to reliability of the bulk electric supply systems in the Mid-Atlantic area.

PSE&G expects to be able to continue to meet the demand for electricity on its system through operation of available equipment and by power purchases. However, if periods of unusual demand should coincide with outages of equipment, PSE&G could find it necessary at times to reduce voltage or curtail load in order to safeguard the continued operation of its system.

### Demand Side Management

Integrated resource planning brings together demand-side and supply-side strategies. In order to encourage DSM, the BPU adopted rules in 1991 providing special incentives to encourage utilities to offer these load management conservation services. The rules are designed to place DSM on an equal regulatory footing with supply side or energy production investments. Both EPAct and Phase I of the Energy Master Plan call for conservation to play a significant role in meeting New Jersey's energy needs over the coming decade. PSE&G's DSM Plan has been approved by the BPU. The IRP calls for PSE&G to utilize conservation and DSM to meet most of the incremental resource needs for the next decade (see Competition).

PSE&G's DSM Plan is designed to encourage investment in energy-saving DSM activities in New Jersey. These activities involve new techniques and technologies, such as high-efficiency lighting and motors, that help reduce customer demand for energy. The DSM Plan consists of two major program areas for both electric and gas: (1) a core program which includes many specialized programs such as energy audits, seal-ups and rebates for high efficiency heating and cooling equipment; and (2) a standard offer program which is performance based and provides payment for measurable energy savings resulting from the installation of qualified measures that improve the energy efficiency of end-uses. PSE&G's most recent IRP includes a demand forecast average compound annual rate of growth through the year 2004 of electric system peak demand of 1.3%. PSE&G's IRP projects 597 MW of passive DSM and 815 MW of active DSM by the year 2004.

PSE&G has established a wholly owned subsidiary, Public Service Conservation Resources Corporation (PSCRC), to offer DSM services. PSCRC has its principal office at 9 Campus Drive, Parsippany, N.J. 07054. PSCRC finances, markets and develops energy conservation projects, mostly within the PSE&G service territory. At December 31, 1995, its assets totaled \$110 million, of which \$88.2 million were project assets and work in progress.

### Electric Generating Capacity

The following table sets forth certain information as to PSE&G's installed generating capacity as of December 31, 1995:

<u>Source</u>	<u>Installed Capacity(MW)</u>	<u>Percentage</u>
Conventional Steam Electric		
Oil-fired(a) .....	1,723	17
Coal-fired New Jersey(b) .....	1,242	12
Coal-fired Pennsylvania (mine mouth)(c) .....	770	7
Combustion Turbine(d) .....	2,724	26
Combined Cycle .....	890	9
Diesel(c) .....	5	—
Nuclear(c)		
New Jersey .....	1,921	18
Pennsylvania .....	930	9
Pumped Storage(c)(d) .....	195	2
Total(e) .....	<u>10,400</u>	<u>100</u>

- (a) Units with aggregate capacity of 836 MW can also burn gas.
- (b) Can also burn gas.
- (c) PSE&G share of jointly owned facilities.
- (d) Primarily used for peaking purposes.
- (e) Excludes 664 MW of nonutility generation and temporary capacity sales of 200 MW to General Public Utilities Corporation.

For additional information, see Item 2. Properties—PSE&G—Electric Properties.

The capacity available at any time may be less than the installed capacity because of temporary outages for inspection, maintenance, repairs, legal and regulatory requirements or unforeseen circumstances.

The maximum one-hour demand (peak load) which PSE&G experienced in 1995 was 9,467 MW, an all time record which occurred on August 2, 1995, when the day's output was 182,404 Megawatthours (MWH) of electricity. (For information concerning sales, output and capacity factors, see Operating Statistics.) The peak load in 1994 was 9,001 MW which occurred on June 15, 1994, when the day's output was 172,362 MWH of electricity.

## Nuclear Operations

Operation of nuclear generating units involves continuous close regulation by the Nuclear Regulatory Commission (NRC). Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements and continuous demonstrations to the NRC that plant operations meet applicable requirements. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. For information concerning the performance of the nuclear units, see Nuclear Performance Standard and Note 12—Commitments and Contingent Liabilities of Notes.

The scheduled 1996, 1997, and 1998 refueling outages, each estimated at eight to ten weeks duration, for PSE&G's five licensed nuclear units are expected to commence in the following months:

	Refueling Outages		
	1996	1997	1998
Salem 1 .....	—	—	—
Salem 2 .....	—	—	February
Hope Creek .....	—	April	October
Peach Bottom 2 .....	September	—	September
Peach Bottom 3 .....	—	September	—

## Salem

Salem Generating Station consists of two 1100 MW pressurized water nuclear reactors (PWR) located in southern New Jersey on the Delaware River. PSE&G owns 42.59% of the Salem units and operates them on behalf of itself and three other owners: PECO—42.59%; Atlantic Electric Company—7.41%; and Delmarva Power and Light Company—7.41%. As of January 31, 1996, PSE&G's net book value for Salem nuclear production units is approximately \$285 million for Salem 1, \$250 million for Salem 2 and \$93 million in common plant between the two units. Each Salem unit represents approximately 4% of PSE&G's installed electric generating capacity and approximately 2% of its total assets.

Salem 1 and 2 have been out of service since May 16, 1995 and June 7, 1995, respectively. Since that time, PSE&G has been engaged in a thorough assessment of each unit to identify and complete the work necessary to achieve safe, sustained, reliable and economic operation. PSE&G has stated that it will keep each unit off line until it is satisfied that the unit is ready to return to service and to operate reliably over the long term and the NRC has agreed that the unit is sufficiently prepared to restart. On June 9, 1995, the NRC issued a Confirmatory Action Letter documenting these commitments of PSE&G.

On December 11, 1995, PSE&G presented its restart plan for both units to the NRC at a public meeting. On February 13, 1996, the NRC staff issued a letter to PSE&G indicating that it had concluded that PSE&G's overall restart plan, if implemented effectively, should adequately address the numerous Salem issues to support a safe plant restart, and describing further actions the NRC will undertake to confirm that PSE&G's actions have resulted in the necessary performance improvements to support safe plant restart.

As a part of PSE&G's comprehensive review, an extensive examination is being performed on the steam generators, which are large heat exchangers used to produce steam to drive the turbines. Within the industry,

certain PWRs other than Salem have experienced cracking in a sufficient number of the steam generator tubes to require various modifications to these tubes and replacement of the steam generators in some cases. Until the current outage, regular periodic inspections of the steam generators for each Salem unit have resulted in repairs of a small number of tubes well within NRC limits. As a result of the experience of other utilities with cracking in steam generator tubes, in April 1995 the NRC issued a generic letter to all utilities with pressurized water reactors. This generic letter requested utilities with pressurized water reactors to conduct steam generator examinations with more sensitive inspection devices capable of detecting evidence of degradation. Subsequently, PSE&G conducted steam generator inspections of the Salem units using the latest technology available, including a new, more sensitive, eddy current testing device.

With respect to Salem 1, the most recent inspection of the steam generators is not complete, but partial results from eddy current inspections in February 1996 using this new technology show indications of degradation in a significant number of tubes. The inspections are continuing and PSE&G has decided to remove several tubes for laboratory examination to confirm the results of the inspections. Removal of the tubes should be completed in March and preliminary results of the state of the Salem 1 tubes from the subsequent laboratory examinations should be known in April. However, based on the results of inspections to date, PSE&G has concluded that the Salem 1 outage, which was expected to be completed in the second quarter of 1996, will be required to be extended for a substantial additional period to evaluate the state of the steam generators and to subsequently determine an appropriate course of action. Degradation of steam generators in PWRs has become of increasing concern for the nuclear industry. Nationally and internationally, utilities have undertaken actions to repair or replace steam generators. In the extreme, degradation of steam generators has contributed to the retirement of several American nuclear power reactors. After the Salem 1 tubes are fully examined, PSE&G will be able to evaluate its course of action in light of NRC and other industry requirements.

The examination of the Salem 2 steam generators was completed in January 1996 using the same testing device used in Salem 1. The results of the Salem 2 inspection are being reviewed again to confirm their results in light of the experience with Salem 1. Although this review has not yet been completed, results to date appear to confirm that the condition of the Salem 2 steam generators is well within current repair limits at the present time. PSE&G will also remove tubes from the Salem 2 steam generators for laboratory analysis to further confirm the results of this testing.

PSE&G had planned to return Salem 1 to service in the second quarter of 1996 and Salem 2 in the third quarter of 1996. As a result of the extent of the recently discovered degradation in the Salem 1 steam generators, PSE&G is focusing its efforts on the return of Salem 2 to service in the third quarter. The conduct of the additional steam generator inspections and testing on Salem 2 is not expected to adversely affect the timing of its restart. However, the timing of the restart is subject to completion of the requirements of the restart plan to the satisfaction of PSE&G and the NRC as well as to the normal uncertainties associated with such a substantial review and improvement of the systems of a large nuclear unit, so that no assurance can be given that the projected return date will be met.

PSE&G's share of additional operating and maintenance expenses associated with Salem restart activities in 1995 was \$16 million, and capital was \$1.9 million. PSE&G's share of total operating and maintenance expenses for both Salem units for the year was \$111 million and capital costs were \$50.8 million. For 1996, PSE&G does not presently expect its share of operating and maintenance expenses or capital costs for Salem station to exceed 1995 amounts; however this could change as a result of the steam generator inspection results referred to above. The outage of a Salem unit causes PSE&G to incur replacement power costs of approximately \$4 to \$6 million per month. Such amounts vary, however, depending on the availability of other generation, the cost of purchased energy and other factors, including modifications to maintenance schedules of other units.

PSE&G's 1995 aggregate capacity factor for its five nuclear units was 62%, below the 65% minimum annual standard established by the BPU (see Nuclear Performance Standard), resulting in a penalty of approximately \$3.5 million. Based upon current projections and assumptions regarding PSE&G's five nuclear units during 1996, including the return of Hope Creek to service in early March, the return of Salem 2 in the

third quarter, and the continued outage of Salem 1 for the remainder of the year, the 1996 aggregate capacity factor would be approximately 57%, which would result in a penalty ranging from \$11 to \$12 million. For a discussion of the proposed elimination of the NPS under the proposed Alternate Rate Plan, see Note 2—Rate Matters of Notes.

An NRC enforcement conference was held on July 28, 1995 related to certain violations of NRC requirements at Salem. The violations included valves that were incorrectly positioned following a plant modification in May 1993, non-conservatism in setpoints for a pressurizer overpressure protection system and several examples of inadequate root cause determination of events, leading to insufficient corrective actions. On October 16, 1995, the NRC imposed cumulative civil penalties of \$600,000 related to these violations. PSE&G did not contest the penalties.

On January 3, 1995, the NRC provided PSE&G with its latest Systematic Assessment of Licensee Performance (SALP) report on Salem for the period between June 20, 1993 and November 5, 1994. SALP is a process pursuant to which the NRC periodically reviews the performance of nuclear power plant operations. SALP reports rate licensee performance in four assessment areas: Operations, Maintenance, Engineering and Plant Support (the Plant Support area includes security, emergency preparedness, radiological controls, fire protection, chemistry and housekeeping). Ratings range from a high of "1" to a low of "3" for each assessment area. Salem received a rating of "3" in the Operations and Maintenance areas, a rating of "2" in Engineering, and a rating of "1" in the Plant Support area. The NRC noted an overall decline in performance and evidenced particular concern with plant and operator challenges caused by repetitive equipment problems and personnel errors. The NRC also noted that although PSE&G has initiated several comprehensive actions within the past year to improve plant performance, and some recent incremental gains have been made, these efforts have yet to noticeably change overall performance at Salem.

On March 21, 1995, representatives of the NRC Staff met with the Boards of Directors of Enterprise and PSE&G to reiterate the previously expressed concerns with regard to Salem's operations. The NRC staff acknowledged that PSE&G had made efforts to improve Salem's operations, including making senior management changes, but indicated that demonstrated sustained results have not yet been achieved.

PSE&G's own assessments, as well as those by the NRC and the Institute of Nuclear Power Operations, indicate that additional efforts are required to further improve operating performance, as reflected in the restart plans referred to above. PSE&G is committed to taking the necessary actions to address Salem's performance needs. It is anticipated that the NRC will continue to maintain a close watch on Salem's restart activities and subsequent operational performance. No assurance can be given as to what, if any, further or additional actions may be taken or required by the NRC to improve Salem's performance.

For certain litigation and potential claims relating to Salem, see Item 3. Legal Proceedings and Note 12—Commitments and Contingent Liabilities of Notes.

### **Hope Creek**

An outage at Hope Creek causes PSE&G to incur replacement energy costs of approximately \$10 to \$16 million per month. Such amounts vary, however, depending upon the availability of other generation, the cost of purchased energy and other factors including modifications to maintenance schedules of other units.

Hope Creek is currently undergoing a refueling and maintenance outage which commenced November 11, 1995. Replacement power costs incurred during the outage are expected to be approximately \$10 million per month. Hope Creek is presently scheduled to return to service in early March 1996.

As a result of an internal allegation report, PSE&G submitted a Licensee Event Report to the NRC on October 14, 1994 which stated that in 1992, the Hope Creek control room was understaffed for approximately three minutes and a decision was made by those involved that the incident did not warrant initiation of NRC

reporting documentation. A meeting with Region I NRC personnel was held on October 18, 1994 in which the NRC expressed a high degree of concern over the issue. Both the NRC and PSE&G investigated the validity of the allegation and, on September 19, 1995, the NRC issued two Level IV violations with no civil penalty for this incident.

A small amount of low-level radioactive material was released to the atmosphere at Hope Creek on April 5, 1995. The release did not exceed federal limits nor pose any danger to the public or plant employees; however, a trailer driven offsite had exceeded the limit for releasing materials and was later cleaned. PSE&G and the NRC have investigated the event, and on June 16, 1995 an enforcement conference was held. On July 20, 1995, the NRC issued a Notice Of Violation for the Hope Creek unplanned release which noted four violations. No fine was issued, partly because of the comprehensive corrective actions taken following the event and the plant's history of limited enforcement action.

On June 29, 1995, the NRC provided PSE&G with the latest periodic SALP report for Hope Creek for the period between June 20, 1993 and April 22, 1995. The Operations, Maintenance and Engineering areas each received a rating of "2", while the Plant Support area received a rating of "1". However, the NRC noted an overall decline in performance in the Operations, Maintenance and Engineering areas compared to the previous SALP period and cited weak root cause analysis as a dominant factor.

On July 8, 1995, during a manual shutdown of Hope Creek in order to repair control room ventilation equipment, operators partially opened a valve for a period of time and inadvertently reduced the effectiveness of the shutdown cooling system. Although the impact of the event to plant safety was minimal, the positioning of the valve and the resulting temperature change violated plant procedures and technical specifications. On July 31, 1995, NRC staff met with plant management concerning this issue and subsequently determined to assign a special inspection team to independently evaluate this event as well as PSE&G's response to it, including PSE&G's procedures and training for operator handling of abnormal conditions. An NRC enforcement conference was held on November 6, 1995. On December 12, 1995, the NRC issued a Level III violation for this event, with a civil penalty of \$100,000. PSE&G did not challenge the fine.

By letter dated January 29, 1996, the NRC requested a meeting with PSE&G senior management to discuss its concerns regarding declining trends in performance at Hope Creek. The meeting has not yet been scheduled but is expected to occur after the restart of Hope Creek from its current refueling and maintenance outage.

### **Peach Bottom**

The outage of a Peach Bottom unit causes PSE&G to incur additional replacement energy costs of approximately \$4 to \$6 million per month per unit. Such amounts vary, however, depending upon the availability of other generation, the cost of purchased energy and other factors including modifications to maintenance schedules of other units.

PSE&G has been advised by PECO that on January 19, 1996, the NRC issued its periodic SALP Report for Peach Bottom for the period May 1, 1994 to October 14, 1995. Peach Bottom received a rating of "1" in the areas of Plant Operations, Maintenance, and Plant Support. Engineering received a rating of "2". The NRC found continued improvement in performance during the period. Operator performance continued to be a strength as well as operations management oversight. Effective engineering management actions to improve the overall self assessment and system performance evaluation programs were noted, as well as good management oversight activities. Response to emerging issues, equipment problems and event related issues were noted as particularly strong. However, lapses in the quality of technical work and in modification implementation indicated inconsistent performance, and resulted in a repeat rating of "2" for the Engineering area. PECO has advised PSE&G that it will be taking actions to address weaknesses discussed in the SALP Report.

PSE&G has been advised by PECO that, by letter dated October 18, 1994, the NRC has approved PECO's request to re-rate the authorized maximum reactor core power levels of both Peach Bottom units by 5% to

3,458 MW from the current limits of 3,293 MW. The amendment of the Peach Bottom 2 facility operating license was effective upon the date of the NRC approval letter and the hardware changes were completed during the Fall 1994 refueling outage. The amendment of the Peach Bottom 3 facility operating license became effective when the hardware changes for Unit 3 were completed during its Fall 1995 refueling outage.

PSE&G has been advised by PECO that on August 2, 1995, the NRC held an enforcement conference regarding three alleged violations identified by the NRC at Peach Bottom. The NRC's findings included alleged violations in control and design activities and technical specification requirements regarding operability of the emergency diesel generators. As a result, on August 17, 1995, the NRC issued PECO a Level III violation with no civil penalty.

### **Other Nuclear Matters**

In 1990, General Electric (GE) reported that crack indications were discovered near the seam welds of the core shroud assembly in a GE Boiling Water Reactor (BWR) located outside the United States. As a result, GE issued a letter requesting that the owners of GE BWR plants take interim corrective actions, including a review of fabrication records and visual examinations of accessible areas of the core shroud seam welds. PSE&G (Hope Creek) and PECO (Peach Bottom) participated in a GE BWR Owners' Group to evaluate this issue and develop long-term corrective actions.

During the Spring 1994 refueling outage, PSE&G inspected the shroud of Hope Creek in accordance with GE's recommendations and found no cracks. In June 1994, an industry group was formed and subsequently established generic inspection guidelines which were approved by the NRC. Due to the age and materials of the Hope Creek shroud and the historical maintenance of low conductivity water chemistry, Hope Creek has been placed in the lowest susceptibility category under these guidelines. Hope Creek must do another shroud inspection during its next refueling outage in 1997, or install a preemptive repair that would maintain the structural integrity of the shroud under all normal and design basis accident conditions for the remaining life of the plant.

PECO has advised PSE&G that Peach Bottom 3 was last examined during its Fall 1995 refueling outage and the extent of cracking identified was determined to be within industry-established guidelines. In a letter to the NRC dated November 3, 1995, PECO concluded that there is a substantial margin for each core shroud weld to allow for continued operation of Unit 3. PECO has also advised that Peach Bottom 2 was examined in October 1994 during its refueling outage. Although some crack indications were identified, PECO advised that they were considered to be much less severe than those found on Unit 3, and no repairs were required to operate Unit 2 for another two-year cycle.

As a separate matter, as a result of several BWR's experiencing clogging of some emergency core cooling system suction strainers, which supply water from the suppression pool for emergency cooling of the core and related structures, the NRC is drafting rules which tentatively require compliance by December 1997. Alternative resolution options will be subject to NRC approval. PSE&G cannot predict what other actions, if any, the NRC may take on this matter.

### **Nuclear Decommissioning**

In accordance with Nuclear Waste Policy Act of 1992, as amended (NWPA), utilities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear utility places funds in independent external trust accounts it maintains to provide for decommissioning. PSE&G currently recovers from its customers the amounts paid into the trust fund over a period of years and would continue to do so under its proposed Alternative Rate Plan (see Note 2—Rate Matters of Notes). For information concerning enrichment of nuclear fuel and nuclear decommissioning costs, see Note 3—PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel of Notes.

## Electric Fuel Supply and Disposal

The following table indicates PSE&G's KWH output by source of energy:

<u>Source</u>	<u>Actual 1995</u>	<u>Estimated 1996</u>
Nuclear		
New Jersey facilities .....	21%	23%
Pennsylvania facilities .....	16	15
Fossil		
Coal		
New Jersey facilities .....	7	9
Pennsylvania facilities .....	12	13
Natural Gas .....	8	10
Residual Oil .....	1	0
Net PJM Interchange and Utility Purchases and NUGs .....	35	30
Total .....	<u>100%</u>	<u>100%</u>

PSE&G's cost of fuel used to generate electricity in the periods shown below was as follows:

Year	NUCLEAR	COAL				NATURAL GAS	OIL	
		NEW JERSEY FACILITIES		PENNSYLVANIA FACILITIES				
	cents/ Million BTU		cents/ Million BTU		cents/ Million BTU	cents/ Million BTU	\$/ Barrel	cents/ Million BTU
		\$/Ton		\$/Ton				
1993	59.3	55.45	203.8	33.73	136.6	221.7	23.44	384.5
1994	62.3	56.31	213.8	34.78	140.7	197.8	22.19	361.02
1995	60.8	58.29	214.0	33.30	134.4	176.6	20.17	324.50

Substantially all of PSE&G's electric sales are made under rates which are currently designed to permit the recovery of increases in energy costs over base costs on a current annual basis. The Alternative Rate Plan filed by PSE&G proposes discontinuing the Levelized Energy Adjustment Clause (LEAC) and NPS and would substantially shift the risks and opportunities involved in managing changes in fuel and replacement power costs from customers to PSE&G. (see Note 2—Rate Matters of Notes.)

## Nuclear Fuel

The supply of fuel for nuclear generating units involves the mining and milling of uranium ore to uranium concentrate, conversion of the uranium concentrate to uranium hexafluoride, enrichment of the uranium hexafluoride gas, conversion of the enriched gas to fuel pellets and fabrication of fuel assemblies.

PSE&G has several long-term contracts with ore operators to process uranium ore to uranium concentrate to meet the currently projected requirements for the Salem and Hope Creek units fully through the year 2000 and, thereafter, 60% of their requirements through the year 2002.

Present contracts for conversion, enrichment and fabrication services to meet the fuel cycle requirements for Salem and Hope Creek units through the years shown in the following table:

<u>Nuclear Unit</u>	<u>Conversion</u>	<u>Enrichment</u>	<u>Fabrication</u>
Salem 1 .....	2000	(1)	2004
Salem 2 .....	2000	(1)	2005
Hope Creek .....	2000	(1)	2000

- (1) 100% coverage through 1998; approximately 50% through 2002; and approximately 30% through 2004. PSE&G does not anticipate any difficulties in obtaining necessary enrichment service for its Salem and Hope Creek units.

PSE&G has been advised by PECO that it has contracts for the purchase of uranium which will satisfy the fuel requirements of Peach Bottom 2 and 3 through 2002. PSE&G has also been advised by PECO that it has contracts for the conversion of uranium concentrates which will be allocated to Peach Bottom 2 and 3 and two other nuclear generating units in which PSE&G does not have an interest, on an as-needed basis.

PECO has also advised PSE&G that it has contracted for the following segments of the nuclear fuel supply cycle for Peach Bottom 2 and 3 through the following years:

<u>Nuclear Unit</u>	<u>Conversion</u>	<u>Enrichment</u>	<u>Fabrication</u>
Peach Bottom 2 .....	1997	2008	1999
Peach Bottom 3 .....	1997	2008	1998

For information regarding the decontamination and decommissioning funds, see Note 3—PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel of Notes.

### **Coal**

Approximately 40% of PSE&G's coal supply for its New Jersey facilities is obtained under a contract which expires in 1999. The balance of the supply is contracted annually from various suppliers, many of whom PSE&G has dealt with on a continuing basis for a number of years, and is supplemented by spot market purchases. The New Jersey Air Pollution Control Code (NJAPCC) permits the burning of coal with a sulfur content of up to 1% at existing coal-fired generating stations including PSE&G's three coal-fired New Jersey units, Hudson 2 and Mercer 1 and 2. The weighted monthly average sulfur content of the coal received at Hudson Station and at Mercer Station must not exceed 1.0% (dry weight basis). PSE&G has been able to obtain sufficient quantities of 1% (or less) sulfur coal and does not presently anticipate any difficulties in obtaining adequate coal supplies to replace expiring contracts. (See Environmental Controls—Air Pollution Control).

PSE&G has approximately a 23% interest in the Keystone and Conemaugh coal-fired generating stations located in Western Pennsylvania and operated by Pennsylvania Electric Company. At least 71% of the fuel required by the Keystone station is supplied by one coal company under a contract which expires December 31, 2004. At least 30% of the fuel required by Conemaugh station is supplied by another coal company under a contract which expires on December 31, 1997. In addition, approximately 18% of Conemaugh's coal requirements is supplied by a short-term contract which expires on November 30, 1996. The balance of the fuel requirements for each station is supplied through spot purchases obtained from local suppliers. The Keystone Conemaugh Projects Office, which runs project administration at these plants on a day to day basis, has advised PSE&G that it does not expect any difficulties in obtaining adequate coal supplies. (See Environmental Controls).

### **Natural Gas**

PSE&G utilizes natural gas available from various spot, short-term and long-term gas contracts, to replace other fuels for electric generation. Presently, there are no effective legal restrictions on the use of natural gas for electric generation in existing plants. However, approval by FERC is required for the interstate transportation of natural gas, either by virtue of existing blanket authority or through individual proceedings. PSE&G does not expect any difficulties in obtaining natural gas supplies.

### **Oil**

PSE&G uses residual oil in its conventional fossil-fired, steam-electric units. The supply of residual oil is furnished by contract suppliers, supplemented by occasional spot market purchases. PSE&G uses distillate fuel in its combustion turbines which is acquired by spot market purchases. PSE&G does not presently anticipate any difficulties in obtaining oil supplies.

## **Nuclear Fuel Disposal**

After spent fuel is removed from a nuclear reactor, it is placed in temporary storage for cooling in a spent fuel pool at the nuclear station site. Under NWPA, the Federal government has entered into contracts for transportation and ultimate disposal of the spent fuel. The Federal government's present policy is that spent nuclear fuel will be accepted for long-term storage at government-owned and operated repositories. However, at present, no such repositories are in service or under construction. In December 1989, the U.S. Department of Energy (DOE) announced that it would not be able to open a permanent, high-level nuclear waste storage facility until 2010, at the earliest. However, the DOE has also indicated that progress on the repository will be delayed beyond 2010 if sufficient funds are not appropriated by the Congress for this program.

In conformity with the NWPA, PSE&G entered into contracts with the DOE for the disposal of spent nuclear fuel from Salem and Hope Creek. Similarly, PECO contracted with the DOE in connection with Peach Bottom 2 and 3. Under these contracts, the DOE is required to take title to the spent fuel at the site, then transport it and provide for its permanent disposal at a cost of one mil per KWH of nuclear generation, subject to such escalation as may be required to assure full cost recovery by the Federal government. In addition, a one-time payment was made to the DOE for permanently discharged spent fuels irradiated prior to 1983.

On April 28, 1995, the DOE published its final interpretation on the nuclear waste acceptance issues in which it stated that it had no legal obligation to begin waste acceptance in 1998, in the absence of a repository or other storage facility. PSE&G's contracts with DOE call for DOE to begin accepting spent fuel from PSE&G in 1998. As a result, on September 7, 1995, PSE&G, along with 24 other utilities and a combination of 48 States, state regulatory agencies and municipal power agencies, filed a lawsuit in the US District Court of Appeals for the District of Columbia Circuit against the DOE to protect its contractual rights.

Pursuant to NRC rules, spent nuclear fuel generated in any reactor can be stored safely and without significant environmental impact in reactor facility storage pools or in independent spent fuel storage installations located at reactor or away-from-reactor sites for at least 30 years beyond the licensed life for reactor operation (which may include the term of a revised or renewed license).

As a result of reracking the two spent fuel pools at Salem, the availability of adequate spent fuel storage capacity is conservatively estimated through 2008 for Salem 1 and 2012 for Salem 2, prior to losing an operational full core discharge reserve. The Hope Creek pool is also fully racked and it is conservatively expected to provide storage capacity until 2006, again prior to losing an operational full core discharge reserve. The units can be safely operated for many years beyond these dates, as pool storage capacity will continue to be available. These dates simply assist in planning the need for additional storage capacity that may be needed to operate the units until the expiration of their operating license. In addition, PECO has advised PSE&G that spent fuel racks at Peach Bottom have storage capacity until 2000 for Unit 2 and 2001 for Unit 3, prior to losing full core reserve capability, and that expansion of storage capacity beyond such dates is being investigated.

## **Low Level Radioactive Waste (LLRW)**

As a by-product of their operations, nuclear generating units, including those in which PSE&G owns an interest, produce LLRW. Such wastes include paper, plastics, protective clothing, water purification materials and other materials. Such materials are accumulated on site and disposed of at a federally licensed permanent disposal facility in Barnwell, South Carolina.

In 1991, New Jersey enacted legislation providing for funding of the estimated \$90 million cost of establishing a LLRW disposal facility. The State would recover the costs through fees paid by LLRW generators. PSE&G's overall share is expected to be about 40% of the total cost and has provided about \$4.8 million to date. New Jersey has introduced a volunteer siting process to establish a LLRW disposal facility by the year 2000. Public meetings have been held across the state in an effort to provide information to and obtain feedback from the public. To date, there have been no volunteers identified.

Because of the uncertainties in disposal, PSE&G built an on-site facility completed in September 1994. This facility provides five years storage for LLRW from Hope Creek and Salem. The facility was used from July 1994 through June 1995, while the Barnwell facility was temporarily unavailable, and emptied when Barnwell re-opened in 1995. It will be used for interim storage of radioactive materials and waste, and if it proves necessary in the future, to temporarily store waste until New Jersey provides a permanent disposal facility.

PECO has advised PSE&G that it has an on-site LLRW storage facility for Peach Bottom, which will provide at least 5 years of temporary storage. PECO has also advised PSE&G that Pennsylvania is pursuing its own LLRW site development via state-selected candidate sites, along with a volunteer plan option. PSE&G has paid \$2.5 million as its share of siting costs due to its ownership in the Peach Bottom units.

### Gas Operations and Supply

PSE&G supplies its gas customers principally with natural gas. PSE&G supplements natural gas with purchased refinery gas and liquefied petroleum gas produced from propane. The adequacy of supply of all types of gas is affected by the nationwide availability of all sources for energy production.

As of December 31, 1995, the daily gas capacity of PSE&G was as follows:

<u>Type of Gas</u>	<u>Therms Per Day</u>
Natural gas .....	23,191,270
Liquefied petroleum gas .....	2,200,000
Refinery gas .....	400,000
Total .....	<u>25,791,270</u>

About 40% of the daily gas capacity is high load factor natural gas and is available every day of the year. The remainder comes from field storage, liquefied natural gas, seasonal sales, contract peaking supply, propane and refinery gas.

PSE&G's total gas sold to and transported for its various customer classes in 1995 was 3.9 billion therms which consisted of approximately 96% natural gas. Included in this amount is 1.6 billion therms of gas delivered to customers under PSE&G's transportation tariffs and individual cogeneration contracts. (See Operating Statistics of PSE&G). During 1995, PSE&G purchased approximately 3.3 billion therms of gas for its combined gas and electric operations directly from natural gas producers and marketers and the balance from interstate pipeline suppliers. These supplies were transported to New Jersey by PSE&G's four interstate pipeline suppliers. This diversification of supply sources provides PSE&G with reliability of supply, purchasing flexibility and lower overall costs.

PSE&G's gas supply contracts expire at various times over the next two to ten years. PSE&G does not presently anticipate any difficulty in negotiating replacement contracts. Since the quantities of gas available to PSE&G under its supply contracts are more than adequate in warm months, PSE&G nominates part of such quantities for storage, to be withdrawn during the winter season, under storage contracts with its principal suppliers. Underground storage capacity currently is approximately 770 million therms. PSE&G does not presently anticipate any difficulty in obtaining adequate supplies of natural gas.

PSE&G's annual average cost of natural gas sendout is shown below:

<u>Year</u>	<u>Cents Per Million BTU(A)</u>
1995 .....	308.00
1994 .....	318.09
1993 .....	327.00

(A) Excludes contribution by PSE&G's electric operating units for a gas reservation charge and natural gas refunds from suppliers.

Substantially all of PSE&G's gas sales are made under rates which are currently designed to permit the recovery of projected increases in the cost of natural gas and gas from supplemental sources, when compared to levels included in base rates, on a current annual basis. (See Note 2—Rate Matters of Notes.)

The demand for gas by PSE&G's customers is affected by customer conservation, economic conditions, weather, the price relationship between gas and alternative fuels and other factors not within PSE&G's control. Presently, the majority of gas sold in interstate commerce has become deregulated. The ability of gas prices to respond to market conditions has improved in recent years because of actions taken by the FERC. Pipeline companies are able to adjust their gas rates up or down through their purchased gas adjustment mechanism more often than the semi-annual filings of prior years. As discussed above in Competition, FERC actions provided pipeline customers, such as PSE&G, with the opportunity to convert a portion of their pipeline sales contracts to transportation agreements and purchase natural gas supplies directly from a producer or other seller of natural gas. This has increased competition in the gas market by encouraging pipeline companies to act as non-discriminatory transporters of natural gas. PSE&G has taken advantage of these actions to lower its overall gas costs through the displacement of higher cost contract supplies with lower cost spot gas purchases and long-term producer contract supplies. (See Competition.)

PSE&G was able to meet all of the demands of its firm customers during the 1994-95 winter season and expects to continue to meet such energy-related demands of its firm customers during the 1995-96 winter season. However, the sufficiency of supply could be affected by several factors not within PSE&G's control, including curtailments of natural gas by its suppliers, the severity of the winter, the extent of energy conservation by its customers and the availability of feedstocks for the production of supplements to its natural gas supply. During the 1995-96 heating season through February 14, 1996, it was necessary for PSE&G to interrupt service to "interruptible" customers for 25 days as permitted by the applicable tariff. During the 1994-95 heating season, service to such customers was interrupted for eight days.

### **Employee Relations**

Enterprise has no employees. As of December 31, 1995, PSE&G and its subsidiaries employed 11,452 persons. Four-year bargaining agreements between PSE&G and its unions, representing 6,746 employees, will expire April 30, 1996. Also at December 31, 1995, EDHI and its subsidiaries employed 523 persons, of which 38 were represented by unions. PSE&G, EDHI and their subsidiaries believe that they maintain satisfactory relationships with their employees.

For information concerning the employee pension plan and other postretirement benefits, see Note 1—Organization and Summary of Significant Accounting Policies, Note 13—Postretirement Benefits Other Than Pensions and Note 14—Pension Plan of Notes.

### **Regulation**

Enterprise has claimed an exemption from regulation by the SEC as a registered holding company under PUHCA, except for Section 9(a)(2) thereof, which relates to the acquisition of 5% or more of the voting securities of an electric or gas utility company. Enterprise is not subject to direct regulation by the BPU, except potentially with respect to certain transfers of control and reporting requirements, and is not subject to regulation by the FERC. The BPU may also impose certain requirements with respect to affiliate transactions between and among PSE&G, Enterprise and Enterprise's nonutility subsidiaries. (See EDHI.)

As a New Jersey public utility, PSE&G is subject to comprehensive regulation by the BPU including, among other matters, regulation of intrastate rates and service and the issuance and sale of securities. As a participant in the ownership and operation of certain generation and transmission facilities in Pennsylvania, PSE&G is subject to regulation by the Pennsylvania Public Utility Commission (PPUC) in limited respects in regard to such facilities.

PSE&G is subject to regulation by FERC and by the Economic Regulatory Administration, both within DOE, with respect to certain matters, including regulation by FERC with respect to interstate sales and exchanges of electric transmission, capacity and energy, including cogeneration and small power production projects being constructed pursuant to PURPA, and accounts, records and reports. PSE&G is also subject to regulation by the United States Department of Transportation (USDOT) with respect to safety standards for pipeline facilities and the transportation of gas under the Natural Gas Pipeline Safety Act of 1968.

In addition, the New Jersey Need Assessment Act (NJNAA) provides that no public utility shall commence construction of any electric facility (as defined in the NJNAA) without having first obtained a Certificate of Need (Certificate of Need) from the Division of Energy Planning and Conservation within the New Jersey Department of Environmental Protection (NJDEP). A Certificate of Need, if granted, is valid for three years, renewable subject to review by the Commissioner of the NJDEP. Under the NJNAA, no state or local agency may issue any license or permit required for any such construction or substantial expansion prior to the issuance of the Certificate of Need. An electric facility is defined under the NJNAA as any electric power generating unit or combination of units at a single site with a capacity of 100 MW or more or any such units added to an existing electric generating facility which will increase its installed capacity by 25% or by more than 100 MW, whichever is smaller. Under NJNAA, a Certificate of Need will be issued only if the NJDEP Commissioner determines that the proposed facility is necessary to meet the projected need for electricity in the area to be served and that no more efficient, economical or environmentally sound alternative is available.

For information concerning nuclear insurance coverages, the BPU's NPS and assessments and the Price-Anderson Amendments Act of 1988, as amended, (Price Anderson) see Note 12—Commitments and Contingent Liabilities of Notes.

The New Jersey Public Utility Accident Fault Determination Act (Fault Act) requires the BPU to make a determination of fault with regard to any accident at any electric generating or transmission facility prior to granting a request by any utility for a rate increase to cover accident-related costs in excess of \$10 million. Fault, as defined in the Fault Act, means any negligent action or omission of any party which either contributed substantially to causing the accident or failed to mitigate its severity.

However, the Fault Act allows the affected utility to file for non-accident related rate increases during such fault determination hearings and to recover contributions to federally mandated or voluntary cost-sharing plans and allows the BPU to authorize the recovery of certain fault-related repair, clean-up, power replacement and damage costs if substantiated by the evidence presented and if authorized in writing by the BPU. The Fault Act could have a material adverse effect on PSE&G's financial position if such an accident were to occur at a PSE&G facility, it was ultimately determined that the accident was due to the fault of PSE&G and the BPU were to deny recovery of all or a portion of the costs related thereto. The Alternative Rate Plan filed by PSE&G proposes discontinuing LEAC and NPS and would substantially shift the risks and opportunities involved in managing changes in fuel and replacement power costs from customers to PSE&G. See Note 2—Rate Matters—Alternative Rate Plan and LEAC of Notes.

Under New Jersey law, the BPU is required to audit all or a portion of the operating procedures and other internal workings of every gas or electric utility subject to its jurisdiction, including PSE&G, at least once every six years. Under the law, the audit may be performed either by the BPU Staff or under the supervision of designated members of such Staff by an independent management consulting firm, chosen by the utility from a list provided by the BPU. The BPU may, upon completion of the audit and after notice and hearing, order the utility to adopt such new practices and procedures that it shall find reasonable and necessary to promote efficient and adequate service to meet public convenience and necessity. The last such management audit of PSE&G was completed in 1991.

In 1992, as a follow-up to its 1991 management audit, the BPU conducted a focused audit of Enterprise's nonutility businesses to ascertain whether nonutility activities had harmed PSE&G. Enterprise has consistently maintained a clear and distinct separation of its utility and nonutility operations and believes that its nonutility

activities have not in any way adversely affected the utility. The results of the focused audit confirmed that there has been no harm to PSE&G as a result of Enterprise's nonutility activities. However, as a result of recommendations made by the BPU's auditors regarding operations and intercompany relationships between PSE&G and EDHI's nonutility businesses, the BPU approved a plan which, among other things, provides: (1) that Enterprise will not permit EDHI's nonutility investments to exceed 20% of Enterprise's consolidated assets without prior notice to the BPU (such assets at December 31, 1995 were approximately 15%); (2) for a restructuring of the PSE&G Board to include nonemployee Enterprise directors with an annual certification by such Board that the business and financing plans of EDHI will not adversely affect PSE&G; (3) for an Enterprise agreement to (a) limit debt supported by the minimum net worth maintenance agreement between Enterprise and Capital to \$750 million, and (b) make a good-faith effort to eliminate such support over a six to ten year period from April 1993; and (4) the payment by EDHI to PSE&G of an affiliation fee of up to \$2 million a year which will be applied by PSE&G through its LGAC and LEAC to reduce utility rates. Effective January 31, 1995, the debt supported by the minimum net worth maintenance agreement will be limited to \$650 million and such affiliation fee will be proportionately reduced as such supported debt is reduced. In addition, Enterprise and EDHI and its subsidiaries continue to reimburse PSE&G for all costs of services provided by employees of PSE&G.

The issue of Enterprise sharing the benefits of consolidated tax savings with PSE&G or its ratepayers was not resolved by the plan approved as a result of the focused audit and remains open. Enterprise believes that PSE&G's taxes should be treated on a stand-alone basis for rate-making purposes, based on the separate nature of the utility and nonutility businesses. However, neither Enterprise nor PSE&G is able to predict what action, if any, the BPU may take concerning consolidation of tax benefits in future proceedings. On July 28, 1995, the BPU reported to PSE&G that it had fully evaluated all available information regarding the 18 recommendations of the Focused Audit conducted by the BPU's consultant and determined that 17 have been implemented pursuant to the BPU's Order Approving Audit Implementation Plans. The remaining issue regarding Enterprise sharing the benefits of consolidated taxes with PSE&G or its ratepayers may be considered in the context of a future base rate case, or in a filing that considers an alternative form of regulation. PSE&G cannot predict what actions, if any, the BPU may take regarding the consolidated tax issue. (See Note 2—Rate Matters—Consolidated Tax Benefits of Notes.)

Construction and operation of nuclear generating facilities are regulated by the NRC. For additional information relating to regulation by the NRC, see Nuclear Operations. In addition, the Federal Emergency Management Agency is responsible for the review in conjunction with the NRC of certain aspects of emergency planning relating to the operation of nuclear plants.

CEA invests in and participates in the development and operation of domestic and foreign cogeneration and power production facilities, which include QFs and EWGs. For additional information, see EDHI—CEA.

The BPU has authority to regulate power sales agreements within the BPU's pricing guidelines to utilities in the State of New Jersey and ascertain that the terms and conditions of agreements with New Jersey utilities are fair and reasonable. For additional information, see EDHI.

### **Environmental Controls**

PSE&G, like most industrial enterprises, is subject to regulation with respect to the environmental impacts of its operations, including air and water quality control, limitations on land use, disposal of wastes, aesthetics and other matters, by various federal, regional, state and local authorities, including the United States Environmental Protection Agency (EPA), the United States Department of Transportation (USDOT), NJDEP, the New Jersey Department of Health, the BPU, the Interstate Sanitation Commission, the Hackensack Meadowlands Development Commission, the Pinelands Commission, the Delaware River Basin Commission, the United States Coast Guard and the United States Army Corps of Engineers. EDC, CEA and EGDC are also subject to similar regulation with respect to operation of their facilities. (See EDHI)

Environmental laws generally require air emissions and water discharges to meet specified limits. They also impose potential joint and several liability, without regard to fault, on the generators of various hazardous substances to manage these materials properly and to clean up property affected by the production and discharge of such substances. Compliance with environmental requirements has caused PSE&G to modify the day-to-day operation of its facilities, to participate in the cleanup of various properties that have been contaminated and to modify, supplement and replace existing equipment and facilities. During 1995, PSE&G expended approximately \$148 million for capital related expenditures to improve the environment and comply with changing regulations. It is estimated that PSE&G will expend approximately \$81 million, \$43 million, \$35 million, \$30 million and \$13 million in the years 1996 through 2000, respectively, for such purposes. Such amounts are included in PSE&G's estimates of construction expenditures. (See MD&A—Liquidity and Capital Resources.)

Preconstruction analyses and projections of the environmental impacts of contemplated activities, discharges and emissions are frequently required by the permitting agency. Before licensing approvals and permits are granted, the agency usually requests a modeling analysis of the effects of a specific action, and of its effect in combination with other existing and permitted activities, and may request the applicant to address emerging environmental issues. Such environmental reviews have caused delays in the proceedings for licensing facilities and similar delays can be expected in the future.

An industry issue with respect to the construction and operation of electric transmission and distribution lines is the alleged adverse health effects of EMF exposure. In 1990, the New Jersey Commission on Radiation Protection (CORP) decided against setting a limit on magnetic fields produced by high-voltage power lines citing the lack of convincing evidence required to determine dangerous levels. Proposed power regulations are currently under study by CORP to cover new power lines and allow existing power lines to continue to function regardless of new rule changes. If revised, the rules would authorize the NJDEP to screen all new power line projects of 100 kilovolts or more using a principle of "as low as reasonably achievable" to demonstrate that all steps within reason, including modest cost, were taken to reduce EMFs. The outcome of EMF study and/or regulations and the public concerns will affect PSE&G's design and location of future electric power lines and facilities and the cost thereof. Such amounts as may be necessary to comply with these new EMF rules and address public concerns cannot be determined at this time, but such amounts could be material.

The New Jersey Environmental Rights Act provides that any person may maintain a court action against any other person to enforce, or to restrain the violation of any statute, regulation or ordinance which is designed to prevent or minimize pollution, impairment or destruction of the environment, or where no such violation exists, to protect the environment from pollution, impairment or destruction. Certain Federal legislation confers similar rights on individuals. The principal laws and regulations relating to the protection of the environment which affect PSE&G's operations are described below.

### **Air Pollution Control**

The Federal Clean Air Act (CAA) imposes emission control requirements across the United States, including requirements related to the emissions of sulfur dioxide and Nitrogen Oxides (NO<sub>x</sub>) and requires attainment of National Ambient Air Quality Standards (NAAQS).

PSE&G's two wholly-owned and operated coal-fired generating stations in New Jersey are presently expected to be able to meet CAA sulfur dioxide requirements with only modest expenditures.

PSE&G also has approximately a 23% interest in Conemaugh and Keystone, coal-fired generating stations located in western Pennsylvania. With respect to Conemaugh, in order to comply with the CAA Sulfur Dioxide Requirements, the station's co-owners, including PSE&G, approved the installation of scrubbers (flue gas desulfurization systems). PSE&G's share of the remaining Conemaugh scrubber cost is less than \$1.0 million and is included in PSE&G's estimate of construction expenditures. Scrubber construction at Conemaugh Unit 2 was completed in November 1995. Keystone is presently expected to comply with the Sulfur Dioxide Requirements by utilizing excess emission allowances from the over-scrubbing of the Conemaugh units.

The CAA established a national emission trading system for Sulfur Dioxide allowances. Yearly allowances have been allocated according to a formula specified by the CAA and applicable to owner/operators of large boilers and power generating equipment.

New Jersey and other Northeastern states have imposed Reasonably Available Control Technology (RACT) requirements on each major source of NO<sub>x</sub>. Additionally, these states have committed to additional overall NO<sub>x</sub> emission reductions on power plants and large industrial boilers of .2 pounds per million BTUs by 1999 with potential additional reductions of .15 pounds per million BTUs by 2003. All of PSE&G's Fossil Generating units are currently in compliance with RACT requirements.

The NJDEP, in concert with other states in the Northeast, is implementing a regional CAA NO<sub>x</sub> allowance emission trading system for power plants and large industrial boilers. This includes the allocation of emission allowances to these sources in 1996. The NO<sub>x</sub> allowance trading system is scheduled to be operational by the beginning of 1999 and could result in additional changes to equipment, methods of operation or fuel.

EPA has promulgated six NAAQS. PSE&G's Fossil Generating Stations are all located in areas of non-attainment for ozone. Each state has the responsibility under the CAA to adopt a plan, and regulations, to attain and maintain compliance to these standards.

In New Jersey, NJDEP is using the New Jersey Air Pollution Control Code (NJAPCC) to achieve compliance with, and maintenance of, the NAAQS. The NJAPCC provides stringent requirements restricting the sulfur content in coal and oil fuels. (See PSE&G—Electric Fuel Supply and Disposal—Coal.) The increased cost of purchasing low-sulfur fuel is offset by rates which are designed to permit the recovery of fuel costs on a current annual basis. In accordance with the proposed Alternative Rate Plan, separate mechanisms would be established to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies or otherwise out of PSE&G's control. (See PSE&G—Electric Fuel Supply and Disposal and Note 2—Rate Matters of Notes.)

The CAA also requires that each major facility apply for and receive a facility-wide operating permit. The facility-wide operating permit terms and conditions are enforceable by both the EPA and NJDEP. PSE&G filed permit applications for its major facilities in New Jersey in 1995. The operating permit program will require some PSE&G facilities to assess emissions, which could require the installation of emission monitoring equipment and changes to facility operations or technology. To the extent estimates of the costs of complying with these requirements through the year 2000 are quantifiable, they are included in PSE&G's construction expenditures. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by State or Federal agencies, although no assurances can be given as to what action may be taken by the BPU. In addition, the revised CAA requirements will increase the cost of producing electricity for the Pennsylvania and Ohio Valley Region Generating units supplying electricity to the PJM and New Jersey. All of PSE&G's current purchased power costs are included in PSE&G's LEAC. (See Note 2—Rate Matters of Notes.)

In non-attainment areas, one of the effects of the CAA is to allow construction or expansion of a facility only upon a showing that any additional emissions from the source will be more than offset by reductions in similar emissions from existing sources. In prevention of significant deterioration areas, construction or expansion of a facility would be permitted only if emissions from the source, together with emissions from other expected new sources, would not violate air quality increments for particulates and sulfur dioxide that are more stringent than NAAQS. All of these requirements may affect PSE&G's ability to locate, construct or expand generating facilities in the future.

PSE&G has been working collaboratively with environmentalists, a select number of other electric utilities in the Northeast, NJDEP and other Northeast environmental regulators, EPA, and a number of large manufacturing companies to achieve significant emission reductions from power plants in the Midwest. PSE&G has also been working with these respective groups to establish a flexible NO<sub>x</sub> and Volatile Organic Compound

("VOC") emissions trading system as a compliance alternative to CAA compliance requirements for industrial facilities, highway and off-highway emission sources, state transportation CAA conformity and automobile inspection and maintenance. Significant emission reductions from Midwest are expected to improve New Jersey's and the Northeast's air quality thereby lessening the need for additional New Jersey emission controls over and beyond those already regulatorily adopted.

These collaborative efforts, coupled with growing environmental regulator and industry concerns for cost-effective compliance with CAA requirements, have resulted in the creation of a thirty-seven state environment forum called Ozone Transport Assessment Group (OTAG). This includes Midwest, Northeast and Southern states east of the Mississippi River. OTAG's charter is to produce consensus recommendations concerning the need for additional emission controls and to identify the level and sources to which those controls should be applied. OTAG is expected to conclude its work by the fall of 1996. If the OTAG process fails to produce consensus that leads to an agreement by individual states to undertake timely necessary control actions, affected downwind states such as those in the Northeast are required as part of their EPA approved 1994 CAA State Implementation Plans to submit petitions to EPA seeking EPA's imposition of controls on upwind states. It is difficult to determine at this time the likely outcome of this process.

Recently, the issue of transported air pollution from the Midwest power plants and their negative impact on air quality in the Northeast has become the subject of concern before the FERC. The FERC has performed a draft environmental impact statement to assess the environmental impact of developing a generic rule by which electric utilities will be required to provide full non-discriminatory transmission access to all wholesale power providers. PSE&G and a number of other utilities, environmental groups and regulators have submitted comments seeking FERC's mitigation of expected additional power plant emissions resulting from the implementation of FERC's open access policies. It is too soon to determine to what extent FERC will act on the concerns raised.

#### **Water Pollution Control**

The Federal Water Pollution Control Act (FWPCA) authorizes the imposition of technology and water-quality based effluent limitations to regulate the discharge of pollutants into the surface waters of the United States through the issuance of National Pollutant Discharge Elimination System (NPDES) permits. The New Jersey Water Pollution Control Act (NJWPCA) authorizes the NJDEP to regulate discharges to surface waters and ground waters of the State through the New Jersey Pollutant Discharge Elimination System (NJPDES) permits. NJDEP also administers the NPDES/NJPDES permit program. Certain PSE&G facilities are directly regulated by NJPDES permits issued pursuant to FWPCA and the NJWPCA.

In addition, the FWPCA also imposes additional requirements with respect to the control of toxic discharges to degraded waterbodies under Section 304(1). Although five PSE&G electric generating stations (Bergen, Hudson, Kearny, Linden and Sewaren) were originally subject to requirements imposed pursuant to Section 304(1), the NJDEP and EPA have proposed delisting these stations from the 304(1) program for the present time.

The FWPCA also authorizes the imposition of less stringent thermal limits pursuant to a variance procedure set forth in Section 316(a) and the regulation of cooling water intake structures pursuant to Section 316(b). PSE&G has filed information with the NJDEP in support of Section 316(a) variance requests and Section 316(b) best technology available determinations for several of its electric generating stations which are pending before the NJDEP presently and may be required to submit information for other stations as a result of the permit renewal process. With respect to Section 316(b) requirements, the EPA initiated a rulemaking procedure in 1994 to develop regulations implementing this provision. Pursuant to a Consent Decree entered by a Federal District Court resolving an action to compel the rulemaking brought by a number of environmental groups including certain of those who opposed the 1994 Salem NJPDES permit, EPA must propose draft regulations on or before July 2, 1999 and promulgate final regulations by August 2001. While the content and scope of these regulations can not be predicted at this time, they may have a considerable effect on agency review of section 316(b) determinations pending in 1999 or after. (see discussions on Hudson, Mercer, and Salem NJPDES permits below.)

The FWPCA and the NJWPCA also authorize the discharge of stormwater from certain facilities including steam electric generating stations. In many instances, this is accomplished through the development of Stormwater Pollution Prevention Plans (SPPP). Similarly, both laws authorize Publicly Owned Treatment Works (POTW) to issue permits for significant industrial users (SIU) of the treatment facility. Certain of PSE&G's facilities have permits under the SPPP and SIU programs.

A brief discussion on pending permit proceedings which have the potential to impose new or more stringent terms or conditions which could require changes to operations or significant expenditures follows:

Hudson Station's NJPDES permit is in the process of being renewed by the NJDEP. As part of that renewal, the NJDEP has requested updated information in connection with PSE&G's 316(a) and 316(b) demonstrations, in part, to address issues identified by a consultant hired by NJDEP. The consultant recommended that Hudson be retrofit to operate with closed cycle cooling to address alleged adverse impacts associated with the thermal discharge and intake structure. PSE&G is in the process of collecting additional data which will be used in the updated demonstrations. PSE&G anticipates submitting these documents to NJDEP in the first quarter of 1998. It is impossible to predict the NJDEP's determinations on these demonstrations; however, PSE&G presently estimates that the cost of retrofitting Hudson to operate with closed cycle cooling could be in excess of \$59 million in 1998 dollars.

NJDEP has advised PSE&G that it is preparing a renewal permit for Mercer Station and, in connection with that renewal, will also be reexamining Mercer's compliance with Section 316(a) and 316(b). This may result in PSE&G's being required to submit updated 316(a) and 316(b) demonstrations for NJDEP review. It is impossible to predict at this time the outcome of such review.

PSE&G is implementing the 1994 NJPDES permit issued for Salem Station which requires, among other things, water intake screen modifications and wetlands restoration. In addition, PSE&G is seeking permits and approvals from various agencies needed to fully implement the special conditions of the permit. No assurances can be given as to receipt of any such additional permits or approvals. The estimated capital cost of compliance with the final permit is approximately \$100 million, of which PSE&G's share is 42.59% and is included in PSE&G's 1996-2000 construction program. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by State or Federal agencies, although no assurances can be given as to what action may be taken by the BPU. PSE&G must apply to renew the Salem permit in March 1999 which renewal application must provide updated Section 316(a) and 316(b) demonstrations for the NJDEP's review. (See the discussion above regarding EPA's Section 316(b) rulemaking.) (See MD&A—Liquidity and Capital Resources—Construction, Investments and Other Capital Requirements Forecast.)

In June, 1995, PSE&G filed an application with the Delaware River Basin Commission (DRBC) seeking a modification to the heat dissipation area previously established based upon the NJDEP's grant of a Section 316(a) variance for Salem Station. DRBC issued a modified Docket in September 1995 granting PSE&G's request. PSE&G must reapply to the DRBC in 1999 for a continuation of this heat dissipation area.

PSE&G anticipates that NJDEP will issue a draft renewal permit for Hope Creek Station in 1996 which will not propose effluent limitations or other requirements significantly more stringent than those in the existing permit.

CEA Eagle Point, Inc. (Eagle Point), an indirect subsidiary of CEA, is a partner in a partnership which owns the Eagle Point Cogeneration Facility (EPC), located in West Deptford, New Jersey. EPC is operated by an affiliate of Eagle Point's partner and provides electricity and steam for an adjacent petroleum refinery (owned and operated by another affiliate of Eagle Point's partner) and sells excess electricity to PSE&G. On January 15, 1995, Eagle Point received a Notice of Violation (NOV) from Region II of EPA alleging violations of certain CAA requirements and limitations related to the air permit at EPC and the adjacent refinery and demanding that such violations be corrected. Eagle Point, its partner and the operator of the refinery are contesting the EPA

conclusion that violations have occurred and have met with staff of EPA and NJDEP to discuss issues related to the NOV. Eagle Point cannot predict whether EPA will take action with respect to the NOV and, if so, what action it may take. Applicable regulations provide EPA with the power to seek to collect criminal and civil penalties for continued violation of the provisions of air permits.

### **Control of Hazardous Substances**

#### **PSE&G Manufactured Gas Plant Remediation Program**

For information regarding PSE&G's Manufactured Gas Plant Remediation Program, see Note 12—Commitments and Contingent Liabilities of Notes.

#### **Other Sites**

A preliminary review of possible mercury contamination at the Kearny Station concluded that an additional study and investigations are required. In 1995, PSE&G entered into a Memorandum of Agreement (MOA) with NJDEP for the Kearny Generating Station pursuant to which PSE&G will conduct a Remedial Investigation (RI) of the site. A Remedial Investigation Work Plan (RIWP) has been filed and is currently under review by the NJDEP. Field work activities associated with the RI will begin after NJDEP approval of the RIWP.

#### **Hazardous Substances**

The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), as amended by the Superfund Amendments and Reauthorization Act of 1986 and the Federal Resource Conservation and Recovery Act of 1976 (RCRA), authorize EPA to issue orders and/or to bring an enforcement action to compel responsible parties to take investigative and/or cleanup actions at any site that is determined to present an imminent and substantial danger to the public or to the environment because of an actual or threatened release of one or more hazardous substances. The New Jersey Spill Compensation and Control Act (Spill Act) provides similar authority to NJDEP. Because of the nature of PSE&G's business, including the production of electricity, the distribution of gas and, formerly, the manufacture of gas, various by-products and substances are or were produced or handled which contain constituents classified as hazardous under one or more of the above laws.

PSE&G generally provides for the disposal or processing of such substances through licensed independent contractors. However, these statutory provisions impose joint and several liability without regard to fault on all allegedly responsible parties, including the generators of the hazardous substances for certain investigative and cleanup costs at sites where these substances were disposed or processed. These statutes also authorize private rights of action for recovery of these costs.

PSE&G has been notified with respect to a number of such sites and the cleanup of these potentially hazardous sites is receiving greater attention from the government agencies involved. Generally, actions directed at funding such site investigations and cleanups include suspected or known allegedly responsible parties. PSE&G's past operations suggest that some remedial action may be required. PSE&G does not expect its expenditures for any such site to have a material effect on its financial position, results of operations or net cash flows.

EPA has determined that a portion of the Passaic River from a point at its confluence with Hackensack River to a point six miles up-river (the Site) is a "facility" within the meaning of that term as defined under CERCLA. EPA has also determined that five corporations are persons within the meaning of CERCLA for purposes of liability under CERCLA with respect to remedial actions at the Site. EPA has publicly indicated that it is continuing an assessment of available information with respect to the identification of other responsible parties. One of these corporations has entered into a consent order with EPA pursuant to which it is obligated to conduct a remedial investigation, human and ecological risk assessment and feasibility study relating to the Site. Field work activities associated with these actions were initiated in the spring of 1995. A report presenting the results of the remedial investigation and risk assessment is scheduled to be filed in the fall of 1997.

PSE&G and certain of its predecessors conducted operations at properties along the Passaic River both within and outside the Site. EPA has not named PSE&G as a responsible party. PSE&G cannot predict what, if any, action EPA or others may take against PSE&G with respect to the Site or, in such event, what contributions PSE&G may be required to make to the costs of these initiatives.

Presently, significant CERCLA/Spill Act actions involving PSE&G include the following:

(1) Claim made in 1985 by U. S. Department of the Interior under CERCLA with respect to the Pennsylvania Avenue and Fountain Avenue municipal landfills in Brooklyn, New York for damages to natural resources. The U.S. Government alleges damages of approximately \$200 million. To PSE&G's knowledge, there has been no action on this matter since 1988.

(2) Claim by EPA, Region III, under CERCLA with respect to a site operated by Sealand Ltd. in Mount Pleasant Township, New Castle County, Delaware. PSE&G and other companies have entered into an Administrative Consent Order (ACO) obligating the signatories thereto to fund a Remedial Investigation and Feasibility Study (RI/FS). PSE&G's share of the costs of actions taken at this site have approximated 25% of such costs. In 1991, EPA entered a Record of Decision (ROD) which determined that no further action was required at the site. The State of Delaware filed comments objecting to this ROD and hired a consultant which has recommended that additional actions be taken at the site based on its review of EPA's files. The State of Delaware required the potentially responsible parties (PRPs) to conduct additional groundwater analyses during 1994. Based on its review of the monitoring data, in 1995, the State of Delaware proposed to require the PRPs to conduct additional groundwater monitoring for a five year period and to reimburse it for its past and future oversight costs associated with this site. Delaware has not yet provided an estimate on its oversight costs.

(3) At the Duane Marine Salvage Corporation Superfund Site in Perth Amboy, Middlesex County, New Jersey, PRPs including PSE&G, had completed an EPA-approved surface removal action during 1986 and EPA had required no further response actions. However, NJDEP ordered that an RI/FS be performed to address or disprove an alleged subsurface contamination and, following negotiations with the PRPs, including PSE&G, an ACO was executed. The PRPs have submitted an RI/FS and a second revised Draft Feasibility Study. In 1994, NJDEP selected a remedy for the site, the total cost of which is estimated to be \$1,500,000. Based upon the claims made and activities taken to date, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(4) Spill Act Directive issued by NJDEP in 1987 to PRPs, including PSE&G, with respect to a site formerly owned and operated by Borne Chemical Company in Elizabeth, Union County, New Jersey, ordering certain interim actions directed at both site security and the off-site removal of certain hazardous substances. Certain PRPs, including PSE&G, signed an ACO with NJDEP to secure the site, which has been completed. After further negotiations, certain other PRPs, including PSE&G, signed a further ACO requiring them to perform a removal action at the site, which was completed in 1992. In 1994, NJDEP issued a third Directive requiring the performance of an RI/FS. Following negotiations with certain PRPs including PSE&G, an MOA regarding the conduct of the RI/FS was executed in 1995. Based upon the claims made and activities taken to date, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(5) A second Directive pursuant to the Spill Act was issued by NJDEP in 1989 to PRPs, including PSE&G, with respect to the PJP Landfill in Jersey City, Hudson County, New Jersey (PJP), ordering payment of operating and maintenance costs of approximately \$150,000 and reasserting claims made in an initial Directive for all past and future costs associated with investigations and remediation of the alleged contamination. Additionally, in 1990, also pursuant to the Spill Act, NJDEP issued a Multi-Site Directive concerning four sites, including PJP. With respect to the PJP site, NJDEP reasserted demands for payment made in earlier Directives. The NJDEP alleges that it has spent approximately \$23 million in interim remedial measures at the PJP site. The NJDEP also alleges that it will incur approximately \$2 million in costs to complete a remedial investigation of the PJP site. PSE&G has made a good-faith payment of approximately \$21,000 to NJDEP pursuant to the Multi-Site Directive in accordance with actions taken by

certain other PRPs named in these Directives. The NJDEP has filed a cost recovery action in Superior Court against certain of the other PRPs named in the Directives. Based upon the claims made and activities taken to date, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(6) Claim by EPA, Region III, under CERCLA with respect to a Superfund Site in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank, Inc., as a non-ferrous scrap reclamation facility. PSE&G, together with several other utilities, is alleged to be liable either to conduct an RI/FS and undertake the necessary cleanup, if any, or to reimburse EPA for the cost of performing these functions. In 1991 these utilities, including PSE&G, entered into an ACO with the EPA to perform an RI/FS, Docket No. III-91-34-DC. The RI/FS was completed and the RI/FS Report was submitted to EPA in October 1994. The RI/FS Report proposes various remedial alternatives for consideration by EPA in its selection of a remedy for the site. In July 1995, the EPA issued its Proposed Remedial Action Plan (PRAP) for the site. The PRAP details the EPA's intention to select a remedy that will cost between \$17 and \$30 million. It is anticipated that EPA will assert a claim against PSE&G and the other utility companies, and perhaps others as well, for the performance or funding of the selected remedy. PSE&G's share of the costs of the proposed remedy is between \$4 and \$8 million or approximately 26% of the total.

(7) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey and occupies approximately two acres on the Trenton Switching Station property. In May 1995, the NJDEP formally notified PSE&G that the Klockner Road site is an open case and that absent voluntary action by PSE&G, the NJDEP would prioritize the site and thereafter take appropriate enforcement action. As a result of this notice, PSE&G is in the process of filing an application for a MOA. Preliminary investigations indicate the potential presence of soil and groundwater contamination at the site. PSE&G's preliminary estimate is that an environmental characterization of the site will cost approximately \$800,000. The cost of any remediation of potential site contamination is not presently estimable.

(8) In *U.S. v. CDMG Realty Co., et al.*, Civil Action No. 89-4246 (NHP) (RJH), pending in the United States District Court for the District of New Jersey, PSE&G and over 60 other entities were joined in January 1995 as additional third-party defendants. Third-party plaintiffs, an association of 44 entities, are essentially seeking contribution and/or indemnification for the expenses they have incurred and will incur as a result of having settled the direct claims of the NJDEP and EPA related to the investigation and remediation of Sharkey's Landfill, located in Parsippany-Troy Hills, Morris County, New Jersey. The claims are all alleged to be brought pursuant to CERCLA and PSE&G is alleged to have arranged for the disposal of industrial wastes at Sharkey's Landfill. The claims with respect to this matter are presently the subject of an alternative dispute resolution proceeding. Based upon the claims made and activities to date, PSE&G estimates that its obligations for this site will be de minimis.

(9) In 1991, the NJDEP issued Directive and Notice to Insurers Number Two (Directive Two) to 24 Insurers and 52 Respondents, including PSE&G in connection with an investigation and remediation of the Global Landfill Site in Old Bridge Township, Middlesex County, New Jersey (Global Site). Directive Two seeks recovery of past and anticipated future NJDEP response costs (\$37.4 million). PSE&G's alleged liability is based on assertions that it generated asbestos-containing materials which were disposed of at the Global Site. In 1991, PSE&G entered into an agreement with the NJDEP and 29 other Directive Two Respondents effecting a partial settlement of the foregoing costs subject to a subsequent reallocation based upon the parties' further development of information concerning their respective proportionate waste contributions to the Global Site. Negotiations are ongoing regarding resolution of the balance of the response costs sought pursuant to Directive Two. In 1993, the NJDEP and various participating PRPs, including PSE&G, executed a Consent Decree whereby the participating PRPs agreed to perform the remedial design and remedial action for the operable unit one remedy as specified in a 1991 ROD (approximate total cost \$30 million). The Consent Decree was executed and entered by the United States District Court for the District of New Jersey in 1993. Subject to a subsequent reallocation, the various parties to the Consent Decree have agreed that PSE&G's contribution under the Consent Decree settlement will be \$300,000 (approximately 1% of the total cost).

(10) In 1991, the New Jersey Department of Law and Public Safety, Division of Law, issued Directive and Notice To Insurers Number One (Directive One) to 50 Insurers and 20 Respondents, including PSE&G,

seeking from the Respondents payment of \$5.5 million of NJDEP's anticipated costs of remedial action and of administrative oversight at the Combe Fill South Sanitary Landfill in Washington and Chester Townships, Morris County, New Jersey (Combe Site). The \$5.5 million represents the NJDEP's 10% share of such anticipated costs pursuant to a cooperative agreement with the United States regarding the selected remedial action. Therefore, total site remediation costs approximate \$50 million. Further, the Directive One Respondents are directed to perform the operation and maintenance of the remedial action including all remedial facilities on the Combe Site. PSE&G's alleged liability is based on the assertion that PSE&G-generated waste oil and water, containing hazardous substances, was transported to the Combe Site and applied to Combe Site roads for dust control. Based upon the claims made and PSE&G's investigation and response to same, PSE&G anticipates that its obligations, if any, with respect to this site will be de minimis.

(11) In *United States of America v. Superior Tube Company, et al.*, Docket No. 89-7421 in the U.S. District Court for the Eastern District of Pennsylvania, PSE&G was served in 1990 with a Third-Party Complaint. Pursuant to CERCLA, the United States filed suit against Superior Tube Company (Superior) and others seeking recovery of past and future costs incurred or to be incurred in the cleanup of the Moyer Landfill located in Collegeville, Pennsylvania. Superior filed a Third-Party Complaint naming approximately 150 third-party defendants, including PSE&G. Superior alleges that PSE&G generated, transported, arranged for the disposal of and/or caused to be deposited certain hazardous substances at the Moyer Landfill. On the basis of those allegations, Superior seeks contribution and/or indemnification from the third-party defendants, including PSE&G, on the United States' action against it. PSE&G has participated in negotiations concerning resolution of the United States' and Superior Tube's claims. Pursuant to settlement negotiations amongst certain direct defendants, certain third party defendants and the plaintiffs, the defending parties participating in said negotiations are currently pursuing the possibility of resolving all potential liability concerning the above referenced matter (excluding any potential liability associated with a future claim, if any, for natural resource damages) on behalf of certain de minimis defending parties, including PSE&G. Based upon the claims made and the above referenced negotiations, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(12) Spill Act Multi-Site Directive (Directive) issued by the NJDEP to PRPs, including PSE&G, listing four separate sites, including the former bulking and transfer facility called the Marvin Jonas Transfer Station (Sewell Site) in Deptford Township, Gloucester County, New Jersey. With regard to the Sewell Site, this Directive ordered approximately 350 PRPs, including PSE&G, to enter into an ACO with NJDEP, requiring them to remediate the Sewell Site. Certain PRPs, including PSE&G, have completed the interim actions directed at both site security and off-site disposal of containers, trailers and contaminated surface soils. PRPs, including PSE&G, are currently fulfilling the terms of a MOA entered into with NJDEP in 1993 to conduct an RI/FS and, if necessary, take remedial action. Based upon the claims made and activities taken to date, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(13) In *Transtech Industries, Inc. et al v. A&Z Septic Clean et al.*, Docket No. 2-90-2578(HAA), filed on October 5, 1992, in the U.S. District Court for the District of New Jersey, PSE&G has been named a defendant in a Complaint which has been filed pursuant to CERCLA, against several hundred parties seeking recovery of past and future response costs incurred or to be incurred in the investigation and/or remediation of the Kin-Buc Landfill, located in Edison Township, Middlesex County, New Jersey. Plaintiffs allege that all named defendants, including PSE&G, are PRPs as generators and/or transporters of various hazardous substances ultimately deposited at the Kin-Buc Landfill. Based upon the claims made and activities taken to date, PSE&G anticipates that its obligations with respect to this site will be de minimis.

(14) In 1993, PSE&G acknowledged service of Plaintiff's Summons and Complaint in a matter entitled *The Fishbein Family Partnership v. PPG Industries, Inc. and Public Service Electric and Gas Company*. Pursuant to CERCLA, the Spill Act and various common law theories of liability, the Plaintiff filed an action seeking declaratory relief regarding responsibility for and recovery of damages and response costs incurred and/or to be incurred as a result of the release or threatened release of hazardous substances at property located in Jersey City, Hudson County, New Jersey. Plaintiff named PPG Industries, Inc. (PPG) and PSE&G as defendants in the above-referenced action. The Plaintiff alleges that defendants are liable

for the damages and relief sought based on their past conduct of industrial operations at the site. The industrial operations referenced in Plaintiff's Complaint include chromium ore processing operations (PPG and its predecessors) and coal gasification operations (PSE&G and its predecessors). PSE&G filed its response to the Plaintiff's Complaint including cross-claims for indemnity and contribution against co-defendant PPG. PSE&G also filed a Third Party Complaint against UGI Utilities, Inc. (UGI) seeking indemnification and contribution as to any liability imposed upon PSE&G attributable to UGI's past conduct of industrial operations on a portion of the site. In March 1995, PSE&G filed an Amended Third Party Complaint extending the time period of PSE&G's allegations concerning UGI's past conduct of industrial operations at the site. In May 1995, an Administrative Stay of this matter was entered pending either an agreement between the NJDEP and PPG as to a cleanup plan for the site or a determination of certain cross-motions for summary judgement filed by Plaintiff and PPG. Based upon the claims made and activities taken to date, PSE&G's potential liability in this matter, if any, is not currently estimable.

#### **Other Potential Liability**

In addition to the sites individually listed above, PSE&G has received 14 claims and/or inquiries concerning prospective enforcement actions by the EPA and/or NJDEP. Such claims/inquiries relate to alleged properties/sites where it has been alleged that an imminent and substantial danger to the public or to the environment exists as a result of an actual or threatened release of one or more hazardous substances. PSE&G's investigation and initial response concerning each such claim and/or inquiry suggests that PSE&G's potential liability, if any, is de minimis.

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## Consolidated Financial Statistics (A)

### ENTERPRISE

	1995	1994	1993	1992	1991
	(Thousands of Dollars where applicable)				
Selected Income Information					
Operating Revenues					
Electric .....	\$ 4,020,842	\$ 3,739,713	\$ 3,696,114	\$ 3,407,830	\$ 3,519,806
Gas .....	1,686,403	1,778,528	1,594,341	1,586,181	1,307,849
Nonutility Activities .....	456,908	404,202	418,135	362,781	283,766
Total Operating Revenues .....	\$ 6,164,153	\$ 5,922,443	\$ 5,708,590	\$ 5,356,792	\$ 5,111,421
Net Income .....	\$ 662,323	\$ 679,033	\$ 600,933	\$ 504,117	\$ 543,035
Earnings per average share of Common Stock .....	\$ 2.71	\$ 2.78	\$ 2.50	\$ 2.17	\$ 2.43
Dividends Paid per Share .....	\$ 2.16	\$ 2.16	\$ 2.16	\$ 2.16	\$ 2.13
Payout Ratio .....	80%	78%	86%	100%	88%
Rate of Return on Average Common Equity (B) .....	12.31%	12.94%	11.91%	10.69%	12.24%
Ratio of Earnings to Fixed Charges .....	2.77	2.76	2.59	2.30	2.54
Book Value per Common Share (C) .....	\$ 22.25	\$ 21.70	\$ 21.07	\$ 20.32	\$ 20.04
Gross Utility Plant .....	\$16,925,280	\$16,566,058	\$15,861,484	\$15,081,907	\$14,426,560
Accumulated Depreciation and Amortization of Utility Plant ..	\$ 5,737,849	\$ 5,467,813	\$ 5,057,104	\$ 4,610,595	\$ 4,243,979
Total Assets .....	\$17,171,439	\$16,717,440	\$16,329,656	\$14,777,732	\$14,804,354
Consolidated Capitalization Common Stock .....	\$ 3,801,157	\$ 3,801,157	\$ 3,772,662	\$ 3,499,183	\$ 3,262,138
Retained Earnings .....	1,643,785	1,510,010	1,361,018	1,282,931	1,282,029
Common Equity .....	5,444,942	5,311,167	5,133,680	4,782,114	4,544,167
Long-Term Debt .....	5,189,791	5,180,657	5,256,321	4,977,579	5,128,373
Preferred Stock without Mandatory Redemption .....	324,994	384,994	429,994	429,994	429,994
Preferred Stock with Mandatory Redemption .....	150,000	150,000	150,000	75,000	—
Monthly Income Preferred Securities .....	210,000	150,000	—	—	—
Total Capitalization .....	\$11,319,727	\$11,176,818	\$10,969,995	\$10,264,687	\$10,102,534

(A) See Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to Consolidated Financial Statements.

(B) Net Income for a twelve-month period divided by the thirteen-month average of Common Equity.

(C) Total Common Equity divided by end-of-period Common Shares outstanding.

## Operating Statistics

### PSE&G

	1995	1994	1993	1992	1991
	(Thousands of Dollars where applicable)				
<b>Electric</b>					
Revenues from Sales of Electricity:					
Residential .....	\$1,274,712	\$1,187,099	\$1,175,875	\$1,037,099	\$1,116,699
Commercial .....	1,853,855	1,734,894	1,678,011	1,554,956	1,575,547
Industrial .....	704,861	686,065	710,206	683,750	728,411
Public Street Lighting .....	54,730	52,353	51,019	47,729	46,400
Total Revenues from Sales to Customers .....	3,888,158	3,660,411	3,615,111	3,323,534	3,467,057
Interdepartmental .....	1,862	1,710	1,737	1,544	1,599
Non-Required Energy and Capacity Revenues.(a) .....	37,179	35,223	48,625	51,313	19,763
Wholesale Energy and Capacity Revenues.(b) .....	19,446	7,481	—	—	—
Total Revenues from Sales of Electricity .....	3,946,645	3,704,825	3,665,473	3,376,391	3,488,419
Other Electric Revenues .....	74,197	34,888	30,641	31,439	31,387
Total Operating Revenues .....	\$4,020,842	\$3,739,713	\$3,696,114	\$3,407,830	\$3,519,806
Sales of Electricity—megawatthours:					
Residential .....	10,885,479	10,594,134	10,631,402	9,816,046	10,505,547
Commercial .....	18,761,863	18,466,863	18,096,312	17,454,352	17,596,569
Industrial .....	9,026,838	9,109,998	9,203,839	9,298,741	9,406,109
Public Street Lighting .....	339,164	334,726	329,828	325,545	320,900
Total Sales to Customers .....	39,013,344	38,505,721	38,261,381	36,894,684	37,829,125
Interdepartmental .....	20,095	17,755	18,514	19,012	19,719
Non-Required Energy Sales.(a) .....	1,047,996	1,320,170	2,245,884	2,116,049	1,858,590
Wholesale Energy Sales.(b) .....	201,610	139,235	—	—	—
Total Sales of Electricity .....	40,283,045	39,982,881	40,525,779	39,029,745	39,707,434
<b>Gas</b>					
Revenues from Sales of Gas:					
Residential .....	\$ 823,302	\$ 889,541	\$ 780,195	\$ 809,559	\$ 699,696
Commercial .....	501,102	510,829	460,340	481,960	426,110
Industrial .....	274,937	312,405	299,762	243,527	138,394
Street Lighting .....	468	491	467	468	468
Total Revenues from Sales to Customers .....	1,599,809	1,713,266	1,540,764	1,535,514	1,264,668
Interdepartmental .....	2,636	3,976	3,078	2,572	2,689
Total Revenues from Sales of Gas .....	1,602,445	1,717,242	1,543,842	1,538,086	1,267,357
Transportation Service Revenues .....	54,427	35,057	37,081	34,739	27,036
Other Gas Revenues .....	29,531	26,229	13,418	13,356	13,456
Total Operating Revenues .....	\$1,686,403	\$1,778,528	\$1,594,341	\$1,586,181	\$1,307,849
Sales of Gas—kilotherms:					
Residential .....	1,258,181	1,337,267	1,280,128	1,265,270	1,140,887
Commercial .....	971,243	945,950	943,054	939,021	893,069
Industrial .....	942,846	912,689	876,421	739,508	399,385
Street Lighting .....	670	668	666	668	666
Total Sales to Customers .....	3,172,940	3,196,574	3,100,269	2,944,467	2,434,007
Interdepartmental .....	6,139	9,316	7,509	5,967	6,174
Total Sales of Gas .....	3,179,079	3,205,890	3,107,778	2,950,434	2,440,181
Transportation Service .....	682,693	544,539	557,403	543,097	381,497
Total Gas Sold and Transported .....	3,861,772	3,750,429	3,665,181	3,493,531	2,821,678

(a) Non-Required—The sale of excess generation both energy and capacity to other power producers.

(b) Wholesale—Consists of sales for resale to municipalities and to an out of state electric cooperative under negotiated contracts. Prior to 1994, these sales for resale were treated as industrial sales.

## EDHI

EDHI, a wholly owned, direct subsidiary of Enterprise, is incorporated under the laws of New Jersey and is the parent company of EDC, CEA, PSRC, EGDC, Capital and Funding. EDHI's principal executive offices are located at One Riverfront Plaza, Newark, New Jersey 07102. EDHI's focus is on investment in the independent energy market. For a discussion of the impact on EDHI of Enterprise's agreement with the BPU regarding utility/nonutility activities, see Regulation.

## EDC

On December 6, 1995, Enterprise announced that EDHI is pursuing the divestiture of EDC. Enterprise anticipates that, subject to satisfying certain conditions, EDHI will divest EDC during 1996, but no formal plan of divestiture has been approved. The decision stems from Enterprise's belief that EDC is not fully recognized in the value of Enterprise's Common Stock and that, with the advent of the energy futures market, it is not necessary for Enterprise to own large volumes of oil and gas.

EDC, a New Jersey corporation, has its principal executive offices at 1000 Louisiana Street, Suite 2900, Houston, Texas 77002. EDC is an oil and gas exploration and production and marketing company with principal operations both onshore and offshore in the southern United States and a growing international production base. EDC will continue to pursue a program to grow its reserve base through a combination of strategic acquisitions, high potential exploration activities and exploitation of its acquired properties and new discoveries. EDC's worldwide 1995 production totaled 99 BCFE. Year-end 1995 proved reserves were 630 billion cubic feet of gas and 48 million barrels of oil, an increase of 6% and a decrease of 1%, respectively, compared to 1994. As of December 31, 1995 and 1994, EDC's consolidated assets aggregated \$756 million and \$729 million, respectively. EDC has operations encompassing about 5.6 million net acres in 13 states, offshore in the Gulf of Mexico and both onshore and offshore in the United Kingdom, Argentina, Senegal, Ireland, Tunisia and China. EDC is exempt from direct regulation by the BPU and FERC except that certain FERC approval is required to transport its gas interstate from its discovery fields. (See Note 1—Summary of Significant Accounting Policies of Notes.)

## CEA

CEA, a New Jersey corporation, has its principal executive offices at 1200 East Ridgewood Avenue, Ridgewood, New Jersey 07450. CEA invests and participates in the development and operation of cogeneration, thermal and power production facilities, which include domestic QFs, two foreign EWGs and one foreign utility company. CEA is expected to be the primary vehicle for EDHI's business growth for the foreseeable future, with emphasis on international projects. CEA's two direct subsidiaries, CEA New Jersey, Inc. (CEA New Jersey) and CEA USA, Inc. (CEA USA), hold certain of its investments. CEA New Jersey's subsidiaries invest in projects in New Jersey selling power to PSE&G. CEA USA's subsidiaries invest in projects selling power to other domestic and foreign entities. CEA and/or its subsidiaries and affiliates have investments in 22 commercially operating cogeneration or independent power projects, one anthracite coal mine and one project under construction. CEA continuously evaluates the status of project development and construction in light of the realities of timely completion and the costs incurred.

CEA's investments in QF projects have been undertaken with other participants because CEA, together with any other utility affiliate, may not own more than 50% of a QF under applicable law subsequent to the in-service date. Projects involving EWGs are not restricted to a 50% investment limitation. CEA's projects are diversified internationally and technologically and are generally financed through non-recourse debt. CEA is an investor in these projects and the electricity produced by the facilities is not part of PSE&G's installed capacity. However, some of such power is being purchased by PSE&G pursuant to long-term contracts with the applicable projects.

As of December 31, 1995 and 1994, CEA's consolidated assets aggregated \$271 million and \$232 million, respectively. (See Note 7—Long-Term Investments of Notes.)

## **PSRC**

PSRC, a New Jersey corporation, has its principal executive offices at One Riverfront Plaza, Newark, New Jersey 07102. PSRC makes primarily passive investments in assets that can provide funds for future growth as well as provide incremental earnings for Enterprise. Investments have been made in leveraged and direct financing leases, project financings, venture capital funds, leveraged buyout funds, real estate limited partnerships and securities. The maturities of the portfolio's investments are also fairly diverse, with some having terms exceeding 30 years. PSRC's leveraged lease investments include a wide range of asset sectors. Some of the transactions in which PSRC and its subsidiaries participate involve other equity investors. PSRC plans to limit new investments to existing commitments and investments related to the energy business.

PSRC has a gas marketing subsidiary which markets natural gas and associated services on an unregulated basis to commercial and industrial gas consumers nationwide.

PSRC is a limited partner in various partnerships and is committed to make investments from time to time, upon the request of the respective general partners. On December 31, 1995, \$58 million remained as PSRC's unfunded commitment subject to call. As of year-end 1995 and 1994, PSRC's long-term investments aggregated \$1.4 and \$1.3 billion, respectively.

## **EGDC**

EGDC, a New Jersey corporation having its principal executive offices at One Riverfront Plaza, Newark, New Jersey 07102, is a nonresidential real estate development and investment business. EGDC has investments in ten commercial real estate properties (two of which are developed) in several states. EGDC's strategy is to preserve and build the value of its assets to allow for the controlled disposition of its properties as the real estate market improves. As of December 31, 1995 and 1994, EGDC's consolidated assets aggregated \$116 million and \$189 million, respectively.

## **Capital**

Capital, a New Jersey corporation, has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07101. Capital serves as a financing vehicle for EDHI's businesses, borrowing on their behalf on the basis of a minimum net worth maintenance agreement with Enterprise. That agreement provides, among other things, that Enterprise (i) maintain its ownership, directly or indirectly, of all outstanding common stock of Capital, (ii) cause Capital to have at all times a positive tangible net worth of at least \$100,000 and (iii) make sufficient contributions of liquid assets to Capital in order to permit it to pay its debt obligations. In 1993, Enterprise agreed with the BPU to make a good-faith effort to eliminate such Enterprise support within six to ten years. Intercompany borrowing rates are established based upon Capital's cost of funds. Effective January 31, 1995, Capital will not have more than \$650 million of debt outstanding at any time. Capital's assets consist principally of demand notes of EDC, CEA and PSRC. As of December 31, 1995 and 1994, Capital had outstanding \$477.5 million and \$632 million, respectively, of its long-term debt. For additional information, see Construction and Capital Requirements—Financing Activities and MD&A—Liquidity and Capital Resources—EDHI.

## **Funding**

Funding, a New Jersey corporation, has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07101. Funding serves as a financing vehicle for EDHI's businesses (excluding EGDC), borrowing on their behalf, as well as investing their short-term funds. Short-term investments are made only if the funds cannot be employed in intercompany loans. Intercompany borrowing rates are established based upon Funding's cost of funds. Funding is providing both long and short-term capital for the nonutility businesses other than EGDC on the basis of an unconditional guaranty from EDHI, but without direct support from Enterprise. As of December 31, 1995 and 1994, Funding's assets consisted principally of demand notes of EDC, CEA and PSRC, all of which are pledged to Funding's lenders and which aggregated \$492 million and \$334 million, respectively. For additional information, see MD&A—Liquidity and Capital Resources—EDHI.

**Item 2. Properties****PSE&G**

The statements under this Item as to ownership of properties are made without regard to leases, tax and assessment liens, judgments, easements, rights of way, contracts, reservations, exceptions, conditions, immaterial liens and encumbrances and other outstanding rights affecting such properties, none of which is considered to be significant in the operations of PSE&G, except that PSE&G's First and Refunding Mortgage (Mortgage), securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of such property.

PSE&G maintains insurance coverage against loss or damage to its principal plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Note 12—Commitments and Contingent Liabilities of Notes to Consolidated Financial Statements.

The electric lines and gas mains of PSE&G are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. These easements and rights are deemed by PSE&G to be adequate for the purposes for which they are being used. Generally, where payments are minor in amount, no examinations of underlying titles as to the rights of way for transmission or distribution lines or mains have been made.

## Electric Properties

As of December 31, 1995, PSE&G's share of installed generating capacity was 10,400 MW, as shown in the following table:

Name and Location	Installed Megawatt Capacity	Principal Fuel Used	Heat Rate	Net Generation (000 mwh)	Capacity Factor(a)
<i>Fossil</i>					
Burlington, Burlington, NJ .....	180	Oil	17,742	30	1.9
Conemaugh, New Florence, PA—22.50%(b)(c) .....	382	Coal	9,380	2,650	79.2
Hudson, Jersey City, NJ .....	983	Coal	11,351	1,861	21.6
Kearny, Kearny, NJ .....	292	Oil	16,221	46	1.8
Keystone, Shelocta, PA—22.84%(b)(c) .....	388	Coal	9,635	2,643	77.8
Linden, Linden, NJ .....	415	Oil	18,007	117	3.2
Mercer, Hamilton, NJ .....	642	Coal	10,279	2,087	37.1
Sewaren, Woodbridge Twp., NJ .....	453	Gas	13,808	360	9.1
Total Fossil .....	3,735		10,343	9,794	29.9
<i>Nuclear</i> (Capacity factor calculated in accordance with industries maximum dependable capability standards)					
Hope Creek, Lower Alloways Creek, NJ 95%(b)(c) .....	979	Nuclear	10,801	6,694	78.9
Peach Bottom, Peach Bottom, PA—42.49%(b) .....	930	Nuclear	10,809	6,976	93.3
Salem, Lower Alloways Creek, NJ 42.59%(b) .....	942	Nuclear	11,088	1,923	23.4
Total Nuclear(b)(c) .....	2,851		10,843	15,593	62.9
<i>Combined Cycle</i>					
Bergen, Ridgefield, NJ .....	650	Gas	8,034	1,533	26.9
Burlington, Burlington, NJ .....	240	Gas	9,255	513	23.5
Total Combined Cycle .....	890		8,340	2,046	26.5
<i>Combustion Turbine</i>					
Bayonne, Bayonne, NJ .....	42	Oil	35,297	0.4	0.1
Bergen, Ridgefield, NJ .....	21	Oil	111,665	0.8	0.1
Burlington, Burlington, NJ .....	389	Gas	18,937	7.1	0.2
Edison, Edison Township, NJ .....	504	Gas	16,532	8.5	0.2
Essex, Newark, NJ .....	617	Gas	13,270	279.1	5.2
Hudson, Jersey City, NJ .....	129	Oil	68,666	0.6	—
Kearny, Kearny, NJ .....	504	Oil	18,352	1.7	0.4
Linden, Linden, NJ .....	223	Oil	12,635	135.0	3.7
Mercer, Hamilton, NJ .....	129	Oil	72,912	0.4	—
National Park, National Park, NJ .....	21	Oil	0	0.0	—
Salem, Lower Alloways Creek, NJ 42.59%(b) .....	16	Oil	25,189	0.3	0.1
Sewaren, Woodbridge Township, NJ .....	129	Oil	45,613	0.8	—
Total Combustion Turbine .....	2,724		13,761	434.7	10.4
<i>Diesel</i>					
Conemaugh, New Florence, PA—22.50%(b) .....	3	Oil	10,101	2.1	0.1
Keystone, Shelocta, PA—22.84%(b) .....	2	Oil	10,448	5.5	3.1
Total Diesel .....	5		10,354	7.6	1.7
<i>Pumped Storage</i>					
Yards Creek, Blairstown, NJ—50%(b)(c) .....	195		—	227	13.3
Total PSE&G .....	10,400(d)		10,531	28,102(e)	30.8

(a) Net generation divided by the product of weighted average generating capacity times total hours.

(b) PSE&G's share of jointly owned facility.

(c) Excludes energy for pumping and synchronous condensers.

(d) Excludes 664 MW of nonutility generation and 200 MW of capacity sales to General Public Utilities Corporation.

(e) Excludes 5,136 MW of nonutility generation.

For information regarding construction see MD&A—Construction and Capital Expenditures.

In addition to the generating facilities in New Jersey and Pennsylvania as indicated in the table above, as of December 31, 1995, PSE&G owned 41 switching stations with an aggregate installed capacity of 31,591,000 kilovolt-amperes, and 222 substations with an aggregate installed capacity of 7,313,000 kilovolt-amperes. In addition, 6 substations having an aggregate installed capacity of 139,250 kilovolt-amperes were operated on leased property. All of these facilities are located in New Jersey.

As of December 31, 1995, PSE&G's transmission and distribution system included 151,449 circuit miles, of which 36,007 miles were underground, and 789,106 poles, of which 534,106 poles were jointly owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 1995, PSE&G owned 4 electric distribution headquarters and five subheadquarters in four operating divisions all located in New Jersey.

### Gas Properties

As of December 31, 1995, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,973,000 therms (approximately 297,300 Mcf. on an equivalent basis of 1,000 Btu/cubic foot) as shown in the following table:

<u>Plant</u>	<u>Location</u>	<u>Daily Capacity (Therms)</u>
Burlington LNG .....	Burlington, N.J.	773,000
Camden LPG .....	Camden, N.J.	280,000
Central LPG .....	Edison Twp., N.J.	960,000
Harrison LPG .....	Harrison, N.J.	960,000
Total .....		<u>2,973,000</u>

As of December 31, 1995, PSE&G owned and operated approximately 15,467 miles of gas mains, owned 12 gas distribution headquarters and one subheadquarters and leased one other subheadquarters all in two operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 61 natural gas metering or regulating stations, all located in New Jersey, of which 28 were located on land owned by customers or natural gas pipeline companies supplying PSE&G with natural gas and were operated under lease, easement or other similar arrangement. In some instances, portions of the metering and regulating facilities were owned by the pipeline companies.

### Office Buildings and Facilities

PSE&G leases substantially all of a 26-story office tower for its corporate headquarters at 80 Park Plaza, Newark, New Jersey, together with an adjoining three-story building. PSE&G also leases other office space at various locations throughout New Jersey for district offices and offices for various corporate groups and services. PSE&G also owns various other sites for training, testing, parking, records storage, research, repair and maintenance, warehouse facilities and for other purposes related to its business.

EDHI owns no real property. EDHI leases its corporate headquarters at One Riverfront Plaza, Newark, New Jersey. For a brief general description of the properties of the subsidiaries of EDHI, see Item 1. Business—EDHI.

### **Item 3. Legal Proceedings**

In October 1995, Enterprise received a letter from a representative of a purported shareholder demanding that it commence legal action against certain of its officers and directors with regard to nuclear operations and the current shutdown of the Salem generating station. In January, 1996, Enterprise and each of its directors except Forrest J. Remick were served with a civil complaint in a shareholder derivative action by such purported shareholder on behalf of Enterprise shareholders (Public Service Enterprise Group Incorporated by G.E. Stricklin, derivatively vs. E. James Ferland, et al., Docket No. L1068395, Superior Court of New Jersey, Law Division, Camden County filed December 27, 1995). The complaint seeks removal of certain executive officers of PSE&G and Enterprise, certain changes in the composition of Enterprise's Board of Directors, recovery of damages and certain other relief for alleged losses purportedly arising out of PSE&G's operation of the Salem and Hope Creek generating stations. The Board of Directors has commenced an investigation of the matters raised in the October demand letter, and that investigation has not yet been completed. Following conclusion of the investigation, the Board will meet to determine what action, if any, should be taken with respect to the complaint filed in the shareholder derivative action.

In addition, see the following, at the pages indicated:

(1) Page 3. Proceedings before FERC relating to competition and electric wholesale power markets. (Inquiry Concerning the Pricing Policy for Transmission Services Provided by Utilities Under the Federal Power Act, Docket No. RM93-19.)

(2) Page 7. Proceedings before the BPU relating to PSE&G's second largest customer, filed January 6, 1995, in Docket No. ER95010005.

(3) Page 24. Requests filed in 1974 and later supplemented, to EPA and NJDEP to establish thermal discharges and intake structures for PSE&G's electric generating stations (Sewaren Generating Station, NJ 0000680; Hudson Generating Station, NJ 0000647; Kearny Generating Station, NJ 0000655; Salem Generating Station, NJ 0005622; Linden Generating Station, NJ 0000663).

(4) Page 25. Notice of Violation issued by EPA against Eagle Point Cogeneration Partnership regarding alleged violations of air permit.

(5) Pages 27 through 30. Various administrative actions, claims, litigation and requests for information by federal and/or state agencies, and/or private parties, under CERCLA, RCRA, and state environmental laws to compel PRPs, which may include PSE&G, to provide information with respect to transportation and disposal of hazardous substances and wastes, and/or to undertake or contribute to the costs of investigative and/or cleanup actions at various locations because of actual or threatened releases of one or more potentially hazardous substances and/or wastes.

(6) Page 73. Proceedings before the BPU relating to New Jersey Partners in Power Plan filed January 16, 1996, in Docket No. E096010028.

(7) Page 75. Proceedings before the BPU relating to PSE&G's LGAC, filed October 2, 1995, in Docket No. GR9510456.

(8) Page 75. Proceedings before the BPU relating to recovery of replacement power costs in connection with the Salem 1 shutdown, May 5, 1995, Docket No. ER94070293.

(9) Page 76. Proceedings before the BPU relating to PSE&G's LEAC Remediation Program Costs (RAC), filed July 21, 1995, in Docket No. GR95070344.

(10) Page 76. Generic proceeding before the BPU relating to recovery of capacity costs associated with power purchases from cogenerators, September 16, 1994, in Docket No. EX93060255.

### **Item 4. Submission of Matters to a Vote of Security Holders**

Enterprise and PSE&G, inapplicable.

### **Item 10. Executive Officers of the Registrants**

Enterprise and PSE&G. Information regarding executive officers required by this Item is set forth in Part III, Item 10 hereof.

## PART II

**Item 5. Market for Registrant's Common Equity and Related Stockholder Matters**

Enterprise's Common Stock is listed on the New York Stock Exchange, Inc. and the Philadelphia Stock Exchange, Inc. All of PSE&G's common stock is owned by Enterprise, its corporate parent. As of December 31, 1995, there were 175,831 holders of record of Enterprise Common Stock.

The following table indicates the high and low sale prices for Enterprise's Common Stock, as reported in The Wall Street Journal as Composite Transactions and dividends paid for the periods indicated:

	<u>High</u>	<u>Low</u>	<u>Dividend Per Share</u>
Common Stock:			
1995			
First Quarter .....	29 $\frac{7}{8}$	26	.54
Second Quarter .....	30 $\frac{1}{4}$	26 $\frac{3}{4}$	.54
Third Quarter .....	29 $\frac{3}{4}$	26 $\frac{3}{4}$	.54
Fourth Quarter .....	30 $\frac{5}{8}$	28 $\frac{3}{4}$	.54
1994			
First Quarter .....	32	27 $\frac{1}{4}$	.54
Second Quarter .....	29 $\frac{1}{4}$	25	.54
Third Quarter .....	28 $\frac{5}{8}$	23 $\frac{7}{8}$	.54
Fourth Quarter .....	27 $\frac{1}{8}$	25	.54

Since 1986, PSE&G has made regular cash payments to Enterprise in the form of dividends on outstanding shares of PSE&G's Common Stock. PSE&G has paid quarterly dividends on its common stock in each year commencing in 1948, the year of the distribution of PSE&G's common stock by Public Service Corporation of New Jersey, the former parent of PSE&G. Since 1992, EDHI has made regular cash payments to Enterprise in the form of dividends on outstanding shares of EDHI's common stock. Enterprise has paid quarterly dividends in each year commencing with the corporate restructuring of PSE&G when Enterprise became the owner of all the outstanding common stock of PSE&G. While the Board of Directors of Enterprise intends to continue the practice of paying dividends quarterly, amounts and dates of such dividends as may be declared will necessarily be dependent upon Enterprise's future earnings, financial requirements and other factors. See MD&A—Dividends.

The ability of Enterprise to declare and to pay dividends is contingent upon its receipt of dividend payments from its subsidiaries. PSE&G has restrictions on the payments of dividends which are contained in its Restated Certificate of Incorporation, as amended, certain of the indentures supplemental to its Mortgage and certain debenture bond indentures. Under these restrictions, dividends on PSE&G's common stock may be paid only out of PSE&G's earned surplus and may not reduce PSE&G's earned surplus to less than \$10 million. PSE&G dividends on common stock would be limited to 75% of Earnings Available for Public Service Enterprise Group Incorporated if payment thereof would reduce PSE&G's Stock Equity to less than 33 1/3% of PSE&G's Total Capitalization and would be limited to 50% of Earnings Available for Public Service Enterprise Group Incorporated if payment thereof would reduce Stock Equity to less than 25% of PSE&G's Total Capitalization, as each of said terms is defined in said PSE&G's debenture bond indentures. Further, under an indenture relating to the loan to PSE&G of the proceeds of the Monthly Income Preferred Securities of Public Service Electric and Gas Capital, L.P. (see Note 4.—Schedule of Consolidated Capital Stock and Other Securities of Notes), dividends may not be paid on PSE&G's capital stock as long as any payments on PSE&G's deferrable interest subordinated debentures issued under said indenture have been deferred or there is a default under said indenture or PSE&G's guarantee relating to the Monthly Income Preferred Securities. None of these restrictions presently limits the payment of dividends out of current earnings. The amount of Enterprise's and PSE&G's consolidated retained earnings not subject to these restrictions at December 31, 1995 was \$1.6 billion and \$1.4 billion, respectively.

## Item 6. Selected Financial Data

### Enterprise

The information presented below should be read in conjunction with Enterprise Consolidated Financial Statements and Notes thereto.

	Years Ended December 31,				
	1995	1994	1993	1992	1991
	(Thousands of Dollars, where applicable)				
Total Operating Revenues .....	\$ 6,164,153	\$ 5,922,443	\$ 5,708,590	\$ 5,356,792	\$ 5,111,421
Net Income .....	\$ 662,323	\$ 679,033	\$ 600,933	\$ 504,117	\$ 543,035
Earnings per average share of					
Common Stock .....	\$ 2.71	\$ 2.78	\$ 2.50	\$ 2.17	\$ 2.43
Dividends paid per share of Common					
Stock .....	\$ 2.16	\$ 2.16	\$ 2.16	\$ 2.16	\$ 2.13
As of December 31:					
Total Assets .....	\$17,170,068	\$16,717,440	\$16,329,656	\$14,777,732	\$14,804,354
Long-Term Liabilities:					
Long-Term Debt .....	\$ 5,189,791	\$ 5,180,657	\$ 5,256,321	\$ 4,977,579	\$ 5,128,373
Other Long-Term Liabilities ....	\$ 199,832	\$ 215,603	\$ 220,159	\$ 146,785	\$ 162,064
Preferred Stock with mandatory					
redemption .....	\$ 150,000	\$ 150,000	\$ 150,000	\$ 75,000	\$ —
Monthly Income Preferred Securities ..	\$ 210,000	\$ 150,000	\$ —	\$ —	\$ —
Ratio of Earnings to Fixed Charges					
plus Preferred Securities Dividend					
Requirements(A) .....	2.77	2.76	2.59	2.30	2.54

(A) Fixed charges include the preferred securities dividend requirements of PSE&G.

### PSE&G

The information presented below should be read in conjunction with PSE&G Consolidated Financial Statements and Notes thereto.

	Years Ended December 31,				
	1995	1994	1993	1992	1991
	(Thousands of Dollars, where applicable)				
Total Operating Revenues .....	\$ 5,707,245	\$ 5,518,241	\$ 5,290,455	\$ 4,994,011	\$ 4,827,655
Net Income .....	\$ 616,964	\$ 659,406	\$ 614,868	\$ 475,936	\$ 545,479
As of December 31:					
Total Assets .....	\$14,555,577	\$14,264,398	\$13,984,298	\$12,273,857	\$12,027,970
Long-Term Liabilities:					
Long-Term Debt .....	\$ 4,586,268	\$ 4,486,787	\$ 4,364,437	\$ 3,978,138	\$ 3,933,389
Other Long-Term Liabilities ....	\$ 199,832	\$ 215,603	\$ 220,159	\$ 146,785	\$ 162,064
Preferred Stock with mandatory					
redemption .....	\$ 150,000	\$ 150,000	\$ 150,000	\$ 75,000	\$ —
Monthly Income Preferred Securities ..	\$ 210,000	\$ 150,000	\$ —	\$ —	\$ —
Ratio of Earnings to Fixed Charges ..	3.25	3.35	3.30	2.70	3.20
Ratio of Earnings to Fixed Charges					
plus Preferred Securities Dividend					
Requirements .....	2.77	2.92	2.89	2.43	2.86

## **Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

### **ENTERPRISE**

Significant factors affecting the consolidated financial condition and the results of operations of Public Service Enterprise Group Incorporated (Enterprise) and its subsidiaries are described below. This discussion refers to the Consolidated Financial Statements and related Notes of Enterprise and should be read in conjunction with such statements and notes.

#### **Overview**

Enterprise has two direct wholly owned subsidiaries, Public Service Electric and Gas Company (PSE&G) and Enterprise Diversified Holdings Incorporated (EDHI). Enterprise's principal subsidiary, PSE&G, is an operating public utility providing electric and gas service in certain areas in the State of New Jersey.

EDHI is the parent of Enterprise's nonutility businesses: Energy Development Corporation (EDC), an oil and gas exploration and production and marketing company; Community Energy Alternatives Incorporated (CEA), an investor in and developer and operator of cogeneration and independent power production (IPP) facilities and exempt wholesale generators (EWGs); Public Service Resources Corporation (PSRC), which has made primarily passive investments; and Enterprise Group Development Corporation (EGDC), a diversified nonresidential real estate development and investment business. EDHI also has two finance subsidiaries: PSEG Capital Corporation (Capital), which provides privately placed debt financing on the basis of a minimum net worth maintenance agreement from Enterprise and Enterprise Capital Funding Corporation (Funding), which provides privately placed debt financing guaranteed by EDHI but without direct support from Enterprise. Enterprise has been conducting a controlled exit from the real estate business since 1993 and, in December 1995, announced that it intends to divest EDC.

As of December 31, 1995 and December 31, 1994, PSE&G comprised 85% of Enterprise assets. For each of the years 1995, 1994 and 1993, PSE&G revenues were 93% of Enterprise's revenues and PSE&G's earnings available to Enterprise for such years were 88%, 91% and 96%, respectively, of Enterprise's net income.

The major factors which will affect Enterprise's future results include general and regional economic conditions, PSE&G's customer retention and growth, the ability of PSE&G and EDHI to meet competitive pressures and to contain costs, the ability to respond to and take advantage of opportunities arising from increasing competition in the utility business, the adequacy and timeliness of rate relief, cost recovery and necessary regulatory approvals, the ability to continue to operate and maintain nuclear programs in accordance with Nuclear Regulatory Commission (NRC) and New Jersey Board of Public Utilities (BPU) requirements, the impact of environmental regulations, continued access to the capital markets and continued favorable regulatory treatment of consolidated tax benefits. (See Note 2—Rate Matters, Note 10—Federal Income Taxes and Note 12—Commitments and Contingent Liabilities of Notes to Consolidated Financial Statements ("Notes").)

#### **Competition**

The regulatory structure which has historically embraced the electric and gas industry is in the process of transition. Legislative and regulatory initiatives, at both the federal and state levels, are designed to promote competition and will continue to impose additional pressures on PSE&G's ability to retain customers. In addition, new technology and interest in self generation and cogeneration have provided customers with alternative sources of energy.

Over the last several years, the gas industry has been transformed. Today, commercial and industrial customers can negotiate their own gas purchases directly with producers or brokers, while PSE&G is required to provide intrastate transportation of such purchased gas to the customers' facilities. Although PSE&G is not providing gas sales service to certain commercial and industrial customers, to date there has been no negative impact on earnings since sales service and transportation service tariffs result in the same non-fuel revenue per

therm. Additionally, as a result of this restructuring, PSE&G has been able to negotiate lower cost gas supplies for those customers who continue to be part of its bundled rate schedules. A potential significant competitive challenge could emerge if interstate pipeline companies are permitted to expand their facilities into PSE&G territory and provide intrastate transportation to customers. However, this type of expansion would require federal and state regulatory approvals not currently in existence.

The restructuring of the electric industry is more complex and evolving at a slower pace than that of the gas industry. Federal legislation, such as the National Energy Policy Act (EPAct) has eased restrictions on independent power producers (IPP) in an effort to increase competition in the wholesale electric generation market. As the barriers to entry in the power production business have been lowered, the construction of cogeneration facilities and independent power production facilities has been growing, with the result of creating lower cost alternatives for large commercial and industrial customers. Presently, PSE&G is in the process of assessing the potential for individual arrangements with commercial and industrial customers which have such competitive alternatives, but PSE&G believes that it does not currently have a material exposure with respect to such customers.

Further, EPAct authorized the Federal Energy Regulatory Commission (FERC) to mandate utilities to transport and deliver or "wheel" energy for the supply of bulk power to wholesale customers. In March 1995, FERC issued a Notice of Proposed Rulemaking (NOPR) that would require utilities to (1) establish open access to all wholesale sellers and buyers, (2) offer transmission service comparable to service they provide themselves and (3) take transmission service under the same tariffs offered to other buyers and sellers. FERC's stated position is that it will ensure that utilities have a fair opportunity to recover prudently incurred investments that could become stranded costs as a result of the NOPR.

In the wholesale electric market, other competitive pressures, such as municipalization, may also have an impact on utilities in the evolving electric power industry. Municipalization involves the acquisition and operation of existing investor-owned facilities by a municipal utility (MUNI) through condemnation, purchase or lease or the construction and operation of duplicate, parallel facilities within a municipal boundary. As a result, utilities, such as PSE&G, could lose customers (residential, commercial and industrial) in the municipality that is served by the MUNI, as well as lose the municipal entity itself as a customer.

EPAct granted the states sole authority to mandate retail wheeling. New Jersey regulators have been reviewing existing regulations in an effort to develop a revised regulatory structure that would afford public utilities, such as PSE&G, increased flexibility to meet the competitive challenges of the future. Phase I of the New Jersey Energy Master Plan (Phase I), a two-phase plan to better manage the future energy needs of the State, has been completed. Phase I called for legislation that would allow New Jersey utilities to propose, subject to BPU approval, alternatives to rate base/rate of return pricing, allow for pricing flexibility under certain standards for customers with competitive options and equalize the impact of tax policies, such as the New Jersey Gross Receipts and Franchise Tax (NJGRT) currently assessed on retail energy utility sales, upon all energy producers. On July 20, 1995, Governor Whitman signed into law legislation which provides utilities the flexibility to propose, subject to BPU approval, alternatives to existing rate base/rate of return pricing and offer negotiated off-tariff agreements to customers with competitive options. On June 1, 1995, the BPU issued its order initiating a formal Phase II proceeding of the Master Plan. The proceeding will address wholesale and retail competition in New Jersey.

Recoverability of stranded costs is largely dependent on the transition rules established by regulators, including FERC and the BPU. Stranded costs that could result as the industry moves to a more competitive environment include investments in generating facilities, transmission assets, purchase power agreements where the price being paid under such an agreement exceeds the market price for electricity and regulatory assets for which recovery is based solely on continued cost based regulation. At this time, management cannot predict the level of stranded costs, if any, or the extent to which regulators will allow recovery of such costs.

Increased competition and the shift of risks and opportunities between rate payers and PSE&G resulting from PSE&G's filing of its proposed Alternative Rate Plan (discussed below) will increase the emphasis upon electric operational reliability, efficiency and cost. While the incremental cost of nuclear production is less expensive than PSE&G's other sources of generation, comparatively high embedded costs for nuclear plants increase the need for PSE&G to optimize the utilization of its nuclear generating capacity in order to make its actual generation output cost competitive.

In order to succeed in this increasingly competitive environment, Enterprise and its subsidiaries have taken the following steps designed to retain customers, reduce costs, improve operations and strategically position itself for future operation:

(1) On January 16, 1996, PSE&G filed its proposed alternative rate plan, the "New Jersey Partners in Power" Plan (Alternative Rate Plan). This seven-year proposed Alternative Rate Plan allows for a transition to a competitive energy marketplace while substantially shifting the business and financial risks and opportunities involved in such transition away from customers to PSE&G. Some of the key features of the proposal are: (a) an indexed or price-capped approach to replace the rate base/rate of return form of regulation including the discontinuance of the electric Levelized Energy Adjustment Clause (LEAC) and the BPU's Nuclear Performance Standard (NPS), (b) a productivity gains sharing mechanism with electric and gas customers, (c) continued recovery of costs associated with activities mandated by state or federal agencies and (d) a program of rewards and penalties based on the performance of certain key overall service indicators, such as the duration of customer power outages compared to a five year average. For a full discussion of the Alternative Rate Plan, see Note 2—Rate Matters of Notes.

(2) PSE&G reorganized its senior nuclear leadership team to address operation and performance issues at PSE&G operated nuclear facilities and completed a thorough work scope assessment of Salem 1 and Salem 2 in order to return these units to safe, reliable operation over the long-term.

(3) PSE&G reorganized to reflect the evolution toward stand-alone energy and energy services businesses designed to compete successfully in the future. The reorganization "unbundled" the services previously provided by the electric and gas businesses. The focus is now on areas of business: Generation, Transmission and Distribution and Customer Services.

(4) Also as part of the corporate reorganization, a new business was created, Enterprise Ventures & Services Corporation, to pursue products and services which can be marketed beyond traditional geographic and industry boundaries. Among these are: natural gas marketing in the wake of deregulation of that industry, conservation and energy management services and a product development venture with AT&T Corp. to pilot and eventually market two-way customer communications systems and services.

(5) PSE&G developed initiatives, including the announced closure of five older, less efficient generating units, to reduce annual fossil generation operating and maintenance expenses, as well as to reduce annual fossil capital expenditures.

(6) PSE&G has established a deleveraging plan to retire more than \$1 billion of outstanding debt over the next five years and to fund its current five-year construction program entirely through internally generated cash.

(7) PSE&G became the first utility in the Northeast to implement a service guarantee program. It covers nine key service areas and provides direct bill credits to customers should PSE&G fail to live up to its promises.

(8) The Strategic Account Marketing Organization was created within PSE&G to provide more individualized service to its 200 largest customers.

(9) PSE&G received BPU approval for its proposed Experimental Hourly Energy Pricing Tariff and the first service agreement thereunder with its second largest customer. This type of agreement serves as an incentive to retain customers with other energy alternatives in PSE&G's customer base, as well as in New Jersey.

(10) Also in 1995, PSE&G completed the Bergen Repowering Project which improved the efficiency and environmental effectiveness of the facility. Fuel costs for the facility will be reduced by approximately \$30 million annually.

(11) CEA pursued business opportunities in certain international markets. During 1995, CEA closed on three projects and a strategic alliance in China and South America.

(12) Enterprise announced that EDHI will pursue the divestiture of EDC. The decision to divest EDC stems from Enterprise's conclusion that ownership of large oil and natural gas reserves is no longer necessary to provide efficient energy solutions to customers and that the true market value of EDC is not reflected in the price of Enterprise Common Stock.

Enterprise and its subsidiaries remain committed to the pursuit of initiatives to contain costs and retain customers.

### **Accounting for the Effects of Regulation**

Currently, PSE&G accounts for the effects of regulation in accordance with Statement of Financial Accounting Standards No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). In accordance with the provisions of SFAS 71, PSE&G defers certain expenses (regulatory assets) on the basis that they will be recovered from customers as part of the ratemaking process. PSE&G believes that if its proposed Alternative Rate Plan is approved essentially as proposed, it would continue to meet the criteria to account for certain utility revenues and expenses in accordance with SFAS 71. However, if future events or regulatory changes limit PSE&G's ability to establish prices to recover its costs, PSE&G might conclude that it no longer meets the application criteria to defer certain expenses in accordance with SFAS 71. If PSE&G were to discontinue the application of SFAS 71, the accounting impact would be an extraordinary, non-cash charge to operations that could be material to the financial position and results of operations of Enterprise and PSE&G.

PSE&G has certain regulatory assets resulting from the use of a level of depreciation expense in the rate making process that is less than the amount that would be recorded under Generally Accepted Accounting Principles (GAAP) for non-regulated companies. PSE&G cannot presently quantify what the financial statement impact may be if depreciation expense were required to be determined absent regulation, but the impact on the financial position and results of operations of PSE&G and Enterprise could be material.

Statement of Financial Accounting Standards No. 121 "Accounting for the Impairment of Long-Lived Assets" (SFAS 121) effective for 1996, establishes accounting standards for the impairment of long-lived assets. SFAS 121 also requires that regulatory assets which are no longer probable of recovery through future revenues be charged to earnings. The adoption of SFAS 121 is not expected to have a material impact on the financial position or results of operations of PSE&G and Enterprise.

### **PSE&G Energy and Fuel Adjustment Clauses**

Under the existing regulatory framework, PSE&G has fuel and energy tariff rate adjustment clauses, the Levelized Gas Adjustment Charge (LGAC) and the LEAC, which are designed to permit adjustments for changes in electric energy and gas supply costs and certain other costs as approved by the BPU, when compared to cost recovery included in base rates. Presently, charges under the clauses are primarily based on energy and gas supply costs which are normally projected over twelve-month periods except for large gas commercial and industrial customers for which commencing January 1, 1996, gas supply costs are projected monthly. The changes in the clauses do not directly affect earnings because such costs are adjusted monthly to match amounts recovered through revenues except for the financing costs of carrying underrecovered balances and required interest payments on net overrecovered balances. Under the clauses, if actual costs differ from the costs recovered, the amount of the underrecovery or overrecovery is deferred. Actual costs otherwise includable in the LEAC are subject to adjustment by the BPU in accordance with the NPS. (See Note 2—Rate Matters and Note 12—Commitments and Contingent Liabilities of Notes.) The Alternative Rate Plan proposes discontinuing

LEAC and NPS and would substantially shift the risks and opportunities involved in managing changes in fuel and replacement power costs from customers to PSE&G.

### **Accounting for Stock Compensation**

Statement of Financial Accounting Standards No. 123 "Accounting for Stock-Based Compensation" (SFAS 123) is effective for fiscal years that begin after December 15, 1995. SFAS 123 establishes financial accounting and reporting standards for stock based compensation plans and includes all arrangements by which employees receive shares of stock or other equity instruments of the employer or by which the employer incurs liabilities to employees in amounts based on the price of the employer's stock. The adoption of SFAS 123 is not expected to have a material impact on the financial position or results of operations of PSE&G and Enterprise.

### **Corporate Policy for the Use of Derivatives**

Enterprise and its subsidiaries have established a policy to use derivatives only for the purpose of managing financial risk and not for speculative purposes. EDHI currently uses derivatives to manage financial risk for EDC and PSRC, including its subsidiary United States Energy Partners (USEP). The derivatives are used to mitigate the impact on earnings of volatile gas prices for EDC and USEP and volatile security prices for PSRC's investing activities. For details, see Note 8—Financial Instruments and Risk Management of Notes. Although PSE&G does not currently use derivatives, if the Alternative Rate Plan is approved as proposed, PSE&G could find derivatives to be a useful and appropriate tool in managing the volatility of fuel prices, among other things.

### **Nuclear Operations**

Operation of the Salem units has continued to present challenges to PSE&G. The units have experienced equipment failures which, combined with personnel errors, have precipitated or contributed to plant events or trips which have led to a number of outages over the lifetime of the units.

Both of the Salem units are currently out of service and their return dates are subject to completion of testing, analysis, repair activity and NRC concurrence that they are prepared to restart. Restart of Salem 1, which had originally been scheduled for the second quarter of 1996, will be delayed for a substantial period as a result of the ongoing steam generator inspection and analysis. Salem 2, which is also undergoing steam generator inspection and analysis is still scheduled to return to service in the third quarter of 1996. The inability to successfully return these units to continuous, safe operation could have a material effect on the financial position, results of operation and net cash flows of Enterprise and PSE&G.

### **Results of Operations**

Earnings per share of Enterprise Common Stock were \$2.71 in 1995, \$2.78 in 1994 and \$2.50 in 1993.

In 1995, Enterprise earnings decreased principally due to increased operating expenses and lower gas sales from PSE&G. These decreases in earnings were partially offset by improved electric sales, EDC revenues resulting from the settlement of litigation related to a take or pay sales contract and from gains realized on sales of properties by EDC.

In 1994, the increase in Enterprise earnings was driven primarily by increased weather related electric and gas sales. Enterprise earnings also benefited from higher investment income from PSRC.

## PSE&G—Earnings Available to Enterprise

	1995 vs. 1994		1994 vs. 1993	
	Amount	Per Share	Amount	Per Share
	(Millions, except Per Share Data)			
PSE&G				
Revenues (net of fuel costs and gross receipts taxes) .....	\$ 38	\$ .16	\$147	\$ .60
Other operation expenses .....	10	.04	(77)	(.32)
Maintenance expenses .....	(4)	(.02)	(4)	(.02)
Depreciation and amortization expenses .....	(39)	(.16)	(41)	(.17)
Federal income taxes .....	(27)	(.11)	14	.06
Interest charges .....	(11)	(.05)	(6)	(.02)
Allowance for Funds used During Construction (AFDC) .....	(2)	(.01)	11	.05
Preferred Securities Dividend Requirements .....	(8)	(.03)	(4)	(.02)
Other income and expenses .....	7	.03	2	.01
Earnings Available to Enterprise .....	<u>\$(36)</u>	<u>\$(.15)</u>	<u>\$ 42</u>	<u>\$ .17</u>

## PSE&G—Revenues

### Electric

Revenues increased \$281 million, or 7.5%, in 1995 from 1994; 1994 revenues increased \$44 million, or 1.2%, compared to 1993. The significant components of these changes follow:

	Increase or (Decrease)	
	1995 vs. 1994	1994 vs. 1993
	(Millions)	
Kilowatthour sales .....	\$ 38	\$ 69
Recovery of energy costs .....	189	(26)
NJGRT .....	12	(4)
Other operating revenues .....	42	5
Total Electric Revenues .....	<u>\$281</u>	<u>\$ 44</u>

### Gas

During 1995, revenues decreased \$92 million, or 5.2%, from 1994; 1994 revenues increased \$184 million, or 11.6%, over 1993. The significant components of these changes follow:

	Increase or (Decrease)	
	1995 vs. 1994	1994 vs. 1993
	(Millions)	
Therm sales .....	\$ (35)	\$ 61
Recovery of fuel costs .....	(78)	121
NJGRT .....	19	(12)
Other operating revenues .....	2	14
Total Gas Revenues .....	<u>\$ (92)</u>	<u>\$ 184</u>

During 1995, electric revenues were impacted by higher residential and commercial sales resulting from a recovering economy, warm summer weather and a modest increase in customer base. In addition, other electric revenues increased principally due to higher miscellaneous revenues from increased capacity sales to unaffiliated utilities and to wholesale customers, service reconnections, temporary services and revenues from Public Service Conservation Resources Corporation (PSCRC), PSE&G's energy services subsidiary. Capacity sales are sales

for the reservation of a specified quantity of PSE&G system generating capacity and must be paid even when the energy is not taken.

In 1995, gas revenues decreased due to the mild winter weather, partially offset by revenues resulting from the rapidly growing off system sales and higher gas service contract revenues. Off system sales are sales of excess gas to brokers and other utilities which are not part of PSE&G's firm customer base. Earnings on these sales are shared between the firm customer and PSE&G on an 80/20 split, respectively.

In 1994, electric and gas revenues benefited from weather related sales which primarily impacted electric commercial sales and all firm gas rate schedules. Other electric revenues increased principally due to increased capacity sales to unaffiliated utilities and increased miscellaneous revenues, partially offset by lower energy sales to the unaffiliated utilities. Other gas revenues were significantly impacted by a one time \$10 million legal settlement of a gas contract.

## **PSE&G—Expenses**

### **Fuel Expenses**

As discussed in the PSE&G Energy and Fuel Adjustment Clauses section, variances in fuel expenses do not directly affect earnings because of the adjustment clause mechanism. However, if the proposed Alternative Rate Plan is adopted as filed, future changes in electric fuel and replacement power costs could impact earnings.

### **Other Operation Expenses**

During 1995, other operation expenses decreased \$10 million from 1994 levels. PSE&G had lower nuclear and miscellaneous production expenses. Nuclear production expenses decreased during 1995 due in part to the extended outage of Salem Units 1 and 2. PSE&G also secured savings in miscellaneous expenditures, such as clerical and office supplies in its steam production area. These savings were partially offset by increased marketing expenditures for customer related programs initiated in 1995.

During 1994, other operation expenses increased \$77 million when compared to 1993 principally due to increased nuclear production expenses which were higher than 1993 levels when Salem had a refueling outage, increased transmission and distribution expenses incurred during the bitter 1994 winter and increased administrative and general expenses primarily due to a rise in personal and property damage claim expenses. The increase in personal and property damage claims was directly related to storm damage and other weather related occurrences.

### **Maintenance Expenses**

Maintenance expense increased \$4 million in 1995 in comparison to 1994 due to the extended outage at Salem Units 1 and 2, partially offset by decreased expenses for electric and gas distribution facilities. Maintenance expense for 1994 was \$4 million higher than in 1993 primarily due to the 1994 Hope Creek refueling outage and increased expenses for gas distribution facilities which resulted from the extremely cold weather during January and February 1994.

### **Depreciation and Amortization Expenses**

Depreciation and Amortization expenses increased \$39 million in 1995 when compared to 1994 and \$41 million in 1994 when compared to 1993. The increases in 1995 and 1994 are attributable to increased depreciation expenses directly related to increases in plant in service.

### **Federal Income Taxes**

In 1995, Federal Income Taxes increased \$27 million from 1994 and 1994 Federal Income Taxes decreased \$14 million from 1993. The 1995 taxes were higher than 1994 principally due to the receipt of a non-taxable

insurance benefit in 1994 and to higher pre-tax operating income. Federal Income Taxes decreased in 1994 due to the receipt of a non-taxable insurance benefit, partially offset by higher pre-tax operating income.

### Interest Charges

In 1995, interest charges were \$11 million higher than in 1994 and, in 1994, interest charges were \$6 million higher than in 1993. The primary reason for the 1995 increase was higher interest charges on miscellaneous liabilities, while the driving force behind the 1994 increase was a higher average daily balance of short-term debt outstanding at higher interest rates.

### Allowance for Funds Used During Construction

In 1995, there was a \$2 million decrease in AFDC income principally due to a decrease in construction expenditures. In 1994, AFDC income was \$11 million higher than the 1993 level due to increased construction resulting from the repowering of the Bergen Generating Station.

### Preferred Securities

Dividend requirements on preferred securities increased \$8 million in 1995 compared to 1994 and \$4 million in 1994 compared to 1993. The increases are the result of the issuance of higher rate Monthly Income Preferred Securities used to redeem certain issues of PSE&G Preferred Stock.

### EDHI—Net Income

	1995 vs. 1994		1994 vs. 1993	
	Amount	Per Share	Amount	Per Share
	(Millions, except Per Share Data)			
PSRC .....	—	—	14	.06
CEA .....	(4)	(.02)	2	.01
EDC .....	23	.10	(34)	(.14)
EGDC .....	1	—	54	.22
Total .....	<u>\$20</u>	<u>\$.08</u>	<u>\$36</u>	<u>\$.15</u>

The net income of EDHI was \$80 million in 1995, a \$20 million increase over 1994. EDC's income increased \$23 million primarily due to the realization of a settlement related to a take-or-pay sales contract. EDC's gains from property sales, higher oil prices and volumes and reduced depreciation, depletion and amortization (DD&A) expenses also contributed to higher earnings but were substantially offset by lower gas prices and volumes. CEA's earnings decreased \$4 million compared to 1994 due to higher interest and development expenses.

The net income of EDHI was \$60 million in 1994. Excluding the impact of an impairment of assets of \$51 million, after tax, by EGDC in 1993, EDHI's earnings in 1994 decreased \$15 million in comparison to 1993. Increased income from PSRC (higher investment income, lower income taxes compared to 1993 which included the effects of a Federal income tax increase and lower interest charges) and CEA (higher income from operating plants) was offset by lower EDC earnings (lower gas volumes and prices and higher exploration and development expenditures due to increased drilling activities).

### Dividends

The ability of Enterprise to declare and pay dividends is contingent upon its receipt of dividend payments from its subsidiaries. PSE&G has made regular payments to Enterprise in the form of dividends on outstanding shares of its common stock since Enterprise was formed in 1986. In addition, commencing in 1992, EDHI has also made payments to Enterprise in the form of dividends on its outstanding common stock. Since 1992,

Enterprise has maintained a constant rate of common stock dividends. Management believes that gradually reducing the common stock dividend payout ratio is a prudent policy.

Dividends paid to holders of Enterprise Common Stock increased \$.5 million during 1995 compared to 1994 and increased \$6 million during 1994 compared to 1993. Such increases were due to the issuance of additional shares of Enterprise Common Stock.

Dividends paid to holders of PSE&G's Preferred Stock decreased \$6.7 million during 1995 compared to 1994 and increased \$2 million during 1994 compared to 1993. The 1995 decrease in such dividends was due to the redemption of certain series of Preferred Stock. The increase in 1994 was due to the issuance of additional shares of Preferred Stock. (See Liquidity and Capital Resources.)

Dividends paid to holders of Monthly Income Preferred Securities of Public Service Electric and Gas Capital, L.P. (Partnership), a limited partnership of which PSE&G is the general partner, increased \$14 million during 1995 compared to 1994. The Partnership's Monthly Income Preferred Securities were first issued in 1994 and were not outstanding for the entire year. The increase in 1995 was due to the issuance of additional securities coupled with the fact that Monthly Income Preferred Securities were outstanding for the entire year. (See Note 4—Schedule of Consolidated Capital Stock and Other Securities of Notes.)

### **Liquidity and Capital Resources**

Enterprise's liquidity is affected by maturing debt, investment and acquisition activities, the capital requirements of PSE&G's and EDHI's construction and investment programs, permitted regulatory recovery of expenses and collection of revenues. Capital resources available to meet such requirements depend upon general and regional economic conditions, PSE&G's customer retention and growth, the ability of PSE&G and EDHI to meet competitive pressures and to contain costs, the adequacy and timeliness of rate relief, cost recovery and necessary regulatory approvals, the ability to continue to operate and maintain nuclear programs in accordance with NRC and BPU requirements, the impact of environmental regulations, continued access to the capital markets and continued favorable regulatory treatment of consolidated tax benefits. (For additional information see the discussion of Competition above and Note 12, Commitments and Contingencies of the Notes.)

### **PSE&G**

PSE&G had utility plant additions of \$686 million, \$887 million and \$890 million, for 1995, 1994 and 1993, respectively, including AFDC of \$36 million, \$38 million and \$27 million, respectively. Construction expenditures were related to improvements in PSE&G's existing power plants, transmission and distribution system, gas system and common facilities. PSE&G also expended \$30 million, \$34 million and \$48 million for the cost of plant removal (net of salvage) in 1995, 1994 and 1993, respectively. Construction expenditures from 1996 through 2000 are expected to aggregate \$2.8 billion, including AFDC. Forecasted construction expenditures are related to improvements in PSE&G's existing power plants (including nuclear fuel), transmission and distribution system, gas system and common facilities. (See Construction, Investments and Other Capital Requirements Forecast below.)

PSE&G expects that it will be able to internally generate all of its capital requirements, including construction expenditures, over the next five years and reduce its debt outstanding by approximately \$1 billion, assuming adequate and timely recovery of costs, as to which no assurances can be given. (See Note 2—Rate Matters and Note 12—Commitments and Contingent Liabilities of Notes.)

### **EDHI**

During the next five years, a majority of EDHI's capital requirements are expected to be provided from operational cash flows. (See Construction, Investments and Other Capital Requirements Forecast below.) CEA is expected to be the primary vehicle for EDHI's business growth. A significant portion of CEA's growth is expected to occur in the international arena due to the current and anticipated growth in electric capacity required

in certain regions of the world. EDC will continue to pursue a program to grow its reserve base through a combination of strategic acquisitions, high potential exploration activities and exploitation of its acquired properties and new discoveries. EDC's worldwide 1995 production totaled 99 BCFE and, at year end, EDC had proved reserves of 920 BCFE. EDC expended approximately \$153 million, \$188 million and \$109 million in 1995, 1994 and 1993, respectively, to acquire, discover or develop domestic and international reserves. Of these expenditures, \$132 million, \$160 million and \$92 million in 1995, 1994 and 1993, respectively, were capitalized. These amounts included capitalized interest of \$4 million, \$4 million and \$3 million, respectively. For discussion regarding the potential divestiture of EDC, see Competition.

PSRC will continue to limit new investments to those related to the energy businesses, while EGDC will exit the real estate business in a prudent manner. Over the next several years, EDHI and its subsidiaries will also be required to refinance a portion of their maturing debt in order to meet their capital requirements. In addition, any divestiture of EDC will require the renegotiation of existing loan agreements of Funding. Any inability to extend or replace maturing debt and or existing agreements at current levels and interest rates may affect future earnings and result in an increase in EDHI's cost of capital.

PSRC is a limited partner in various limited partnerships and is committed to make investments from time to time, upon the request of the respective general partners. At December 31, 1995, \$58 million remained as PSRC's unfunded commitment subject to call.

EDHI and each of its subsidiaries are subject to restrictive business and financial covenants contained in existing debt agreements and are required to not exceed various debt to equity ratios which vary from 3:1 to 1.75:1. EDHI is also required to maintain a twelve-months earnings before interest and taxes to interest (EBIT) coverage ratio of at least 1.35:1. As of December 31, 1995 and 1994, EDHI had a consolidated debt to equity ratio of 1.15:1 and, for the years ended December 31, 1995, 1994 and 1993, EBIT coverage ratios, as defined to exclude the effects of EGDC, of 2.47:1, 1.94:1 and 2.13:1, respectively. Compliance with applicable financial covenants will depend upon future financial position and levels of earnings, as to which no assurance can be given. (See Note 6—Schedule of Consolidated Debt and Note 16—Property Impairment of Enterprise Group Development Corporation of Notes.)

#### **Long-Term Investments and Real Estate**

Long-term investments and real estate increased \$82 million in 1995 and decreased \$58 million and \$67 million in 1994 and 1993, respectively. The increase in 1995 was primarily due to an increase in PSRC's long-term investments of \$49 million, PSRC's increase in investments in partnerships and leases of \$52 million and CEA's increase in partnership investments of \$27 million, partially offset by EGDC's property sales of \$53 million. The decrease in 1994 was primarily due to a \$73 million net decrease in PSE&G's investment in an insurance contract, partially offset by an increase in long-term investments of \$23 million. The decrease in 1993 was due primarily to EDHI's decrease in long-term investments of \$63 million. (For more details, see Note 7—long-term investments and Note 11—Leasing Activities—As Lessor of Notes.)

## Construction, Investments and Other Capital Requirements Forecast

	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>TOTAL</u>
	(Millions of Dollars)					
PSE&G (including AFDC)						
Electric (including Nuclear) .....	\$ 464	\$ 408	\$ 383	\$356	\$ 342	\$1,953
Gas .....	128	117	110	106	102	563
Miscellaneous Corporate .....	70	56	50	41	35	252
Total PSE&G Construction Requirements .....	<u>662</u>	<u>581</u>	<u>543</u>	<u>503</u>	<u>479</u>	<u>2,768</u>
EDHI .....	<u>272</u>	<u>148</u>	<u>229</u>	<u>206</u>	<u>225</u>	<u>1,080</u>
MANDATORY RETIREMENT OF SECURITIES:						
PSE&G .....	345	400	118	100	400	1,363
EDHI .....	91	125	195	200	78	689
	<u>436</u>	<u>525</u>	<u>313</u>	<u>300</u>	<u>478</u>	<u>2,052</u>
WORKING CAPITAL AND OTHER—NET .....	<u>16</u>	<u>(26)</u>	<u>70</u>	<u>(21)</u>	<u>59</u>	<u>98</u>
Total Capital Requirements .....	<u>\$1,386</u>	<u>\$1,228</u>	<u>\$1,155</u>	<u>\$988</u>	<u>\$1,241</u>	<u>\$5,998</u>

While the above forecast includes capital costs to comply with revised Federal Clean Air Act (CAA) requirements through 2000, it does not include additional requirements being developed under the CAA by Federal and State agencies. Such additional costs cannot be reasonably estimated at this time. PSE&G believes that such CAA costs would be recoverable from electric customers. In accordance with the proposed Alternative Rate Plan, separate mechanisms would be established to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies or otherwise out of PSE&G's control.

### Internal Generation of Cash from Operations

Enterprise's cash from operations is generated primarily from the operating activities of PSE&G.

Enterprise's cash provided by operations for 1995 increased \$261 million to \$1.493 billion from 1994. This increase was primarily due to the increase in PSE&G's revenues (partially offset by an increase in accounts receivable and unbilled revenues), an increase in the recovery of electric energy and gas costs through PSE&G's LEAC and LGAC and a decrease in PSE&G's gross receipts taxes. For additional information see Results of Operations.

Enterprise's cash provided by operations for 1994 increased \$200 million to \$1.232 billion from 1993. This increase was primarily due to the increase in PSE&G's revenues (plus a decrease in accounts receivable and unbilled revenues) and an increase in the recovery of electric energy and gas costs through PSE&G's LEAC and LGAC. For additional information see Results of Operations.

### External Financings—PSE&G

In 1995, PSE&G issued \$156 million of its First and Refunding Mortgage Bonds (Bonds)/Medium-Term Notes (MTNs) for the purpose of redeeming \$56 million of its higher cost Bonds and to pay a portion of its maturing bonds.

In 1995, Partnership issued \$60 million of Monthly Income Preferred Securities, the proceeds of which were used to redeem \$60 million of PSE&G's Preferred Stock.

The BPU has authorized PSE&G to issue approximately \$4.375 billion aggregate amount of additional Bonds/MTNs/Preferred Stock/Monthly Income Preferred Securities through 1997 for refunding purposes. Under its Mortgage, PSE&G may issue new Bonds against retired Bonds and as of December 31, 1995, up to

\$2.840 billion aggregate amount of new Bonds against previous additions and improvements to utility plant, provided that the ratio of earnings to fixed charges is at least 2:1. At December 31, 1995 the ratio was 2.77:1.

In January 1996, PSE&G issued \$350 million of Bonds. In February 1996, the net proceeds from the sale were deposited in an escrow account for the purpose of refunding certain higher cost bonds at their respective first optional redemption dates in November 1996 and February 1997.

The BPU has authorized PSE&G to issue and have outstanding at any one time not more than \$1 billion of its short-term obligations, consisting of commercial paper and other unsecured borrowings from banks and other lenders through January 1, 1997. On December 31, 1995, PSE&G had \$449 million of short-term debt outstanding.

To provide liquidity for its commercial paper program, PSE&G has a \$500 million one year revolving credit agreement expiring in August 1996 and a \$500 million five year revolving credit agreement expiring in August 2000 with a group of commercial banks, which provides for borrowing up to one year. On December 31, 1995, there were no borrowings outstanding under these credit agreements. PSE&G expects to be able to renew the credit agreement expiring in 1996.

PSCRC has a \$30 million revolving credit facility supported by a PSE&G subscription agreement in an aggregate amount of \$30 million which terminates on March 7, 1996. PSCRC is presently in the process of negotiating a one year extension for this facility. As of December 31, 1995, PSCRC had \$30 million outstanding under this facility.

PSE&G Fuel Corporation (Fuelco) has a \$150 million commercial paper program to finance a 42.49% share of Peach Bottom nuclear fuel, supported by a \$150 million revolving credit facility with a group of banks, which expires on June 28, 1996. PSE&G has guaranteed repayment of Fuelco's respective obligations. As of December 31, 1995, Fuelco had commercial paper of \$88 million outstanding under such program.

#### **External Financings—EDHI**

Funding has a commercial paper program, supported by a commercial bank letter of credit and credit facility, in the amount of \$225 million expiring in March 1998. As of December 31, 1995, Funding had \$182 million of borrowings outstanding under this commercial paper program.

Additionally, Funding has a \$225 million revolving credit facility expiring in March 1998. As of December 31, 1995, Funding had \$100 million of borrowings outstanding under this facility.

Capital's MTN program has previously provided for an aggregate principal amount of up to \$750 million of MTNs so that its total debt outstanding at any time, including MTNs, would not exceed such amount. Effective January 31, 1995, Capital will not have more than \$650 million of debt outstanding at any time. In 1995, Capital repaid \$112 million of its MTNs. At December 31, 1995, Capital had total debt outstanding of \$478 million, including \$355 million of MTNs.

#### **PSE&G**

The information required by this item is incorporated herein by reference to the following portions of Enterprise's Management's Discussion and Analysis of Financial Condition and Results of Operations, insofar as they relate to PSE&G and its subsidiaries: Overview; Competition; PSE&G Energy and Fuel Adjustment Clauses; Accounting for Stock Compensation; Corporate Policy for the Use of Derivatives; Nuclear Operations; Results of Operations; Dividends; Liquidity and Capital Resources; Long-Term Investments and Real Estate; Construction; Investments and Other Capital Requirements Forecast; and External Financings.

## **Item 8. Financial Statements and Supplementary Data**

### **FINANCIAL STATEMENT RESPONSIBILITY—ENTERPRISE**

Management of Enterprise is responsible for the preparation, integrity and objectivity of the consolidated financial statements and related notes of Enterprise. The consolidated financial statements and related notes are prepared in accordance with generally accepted accounting principles. The financial statements reflect estimates based upon the judgment of management where appropriate. Management believes that the consolidated financial statements and related notes present fairly Enterprise's financial position and results of operations. Information in other parts of this Annual Report is also the responsibility of management and is consistent with these consolidated financial statements and related notes.

The firm of Deloitte & Touche LLP, independent auditors, is engaged to audit Enterprise's consolidated financial statements and related notes and issue a report thereon. Deloitte & Touche's audit is conducted in accordance with generally accepted auditing standards. Management has made available to Deloitte & Touche, all the corporation's financial records and related data, as well as the minutes of directors' meetings. Furthermore, management believes that all representations made to Deloitte & Touche, during its audit were valid and appropriate.

Management has established and maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded, and that transactions are executed in accordance with management's authorization and recorded properly for the prevention and detection of fraudulent financial reporting, so as to maintain the integrity and reliability of the financial statements. The system is designed to permit preparation of consolidated financial statements and related notes in accordance with generally accepted accounting principles. The concept of reasonable assurance recognizes that the costs of a system of internal accounting controls should not exceed the related benefits. Management believes the effectiveness of this system is enhanced by an ongoing program of continuous and selective training of employees. In addition, management has communicated to all employees its policies on business conduct, safeguarding assets and internal controls.

The Internal Auditing Department of PSE&G conducts audits and appraisals of accounting and other operations of Enterprise and its subsidiaries and evaluates the effectiveness of cost and other controls and recommends to management, where appropriate, improvements thereto. Management has considered the internal auditors' and Deloitte & Touche's recommendations concerning the corporation's system of internal accounting controls and has taken actions that, in its opinion, are cost-effective in the circumstances to respond appropriately to these recommendations. Management believes that, as of December 31, 1995, the corporation's system of internal accounting controls is adequate to accomplish the objectives discussed herein.

The Board of Directors of Enterprise carries out its responsibility of financial overview through its Audit Committee, which presently consists of six directors who are not employees of Enterprise or any of its affiliates. The Audit Committee meets periodically with management as well as with representatives of the internal auditors and Deloitte & Touche. The Audit Committee reviews the work of each to ensure that its respective responsibilities are being carried out and discusses related matters. Both the internal auditors and Deloitte & Touche periodically meet alone with the Audit Committee and have free access to the Audit Committee, and its individual members, at any time.

E. JAMES FERLAND  
Chairman of the Board,  
President and Chief Executive Officer

ROBERT C. MURRAY  
Vice President and  
Chief Financial Officer

PATRICIA A. RADO  
Vice President and Controller  
Principal Accounting Officer

February 14, 1996

## **FINANCIAL STATEMENT RESPONSIBILITY—PSE&G**

Management of PSE&G is responsible for the preparation, integrity and objectivity of the consolidated financial statements and related notes of PSE&G. The consolidated financial statements and related notes are prepared in accordance with generally accepted accounting principles. The financial statements reflect estimates based upon the judgment of management where appropriate. Management believes that the consolidated financial statements and related notes present fairly PSE&G's financial position and results of operations. Information in other parts of this Annual Report is also the responsibility of management and is consistent with these consolidated financial statements and related notes.

The firm of Deloitte & Touche LLP, independent auditors, is engaged to audit PSE&G's consolidated financial statements and related notes and issue a report thereon. Deloitte & Touche's audit is conducted in accordance with generally accepted auditing standards. Management has made available to Deloitte & Touche, all the corporation's financial records and related data, as well as the minutes of directors' meetings. Furthermore, management believes that all representations made to Deloitte & Touche, during its audit were valid and appropriate.

Management has established and maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded, and that transactions are executed in accordance with management's authorization and recorded properly for the prevention and detection of fraudulent financial reporting, so as to maintain the integrity and reliability of the financial statements. The system is designed to permit preparation of consolidated financial statements and related notes in accordance with generally accepted accounting principles. The concept of reasonable assurance recognizes that the costs of a system of internal accounting controls should not exceed the related benefits. Management believes the effectiveness of this system is enhanced by an ongoing program of continuous and selective training of employees. In addition, management has communicated to all employees its policies on business conduct, safeguarding assets and internal controls.

The Internal Auditing Department conducts audits and appraisals of accounting and other operations and evaluates the effectiveness of cost and other controls and recommends to management, where appropriate, improvements thereto. Management has considered the internal auditors' and Deloitte & Touche's recommendations concerning the corporation's system of internal accounting controls and has taken actions that are cost-effective in the circumstances to respond appropriately to these recommendations. Management believes that, as of December 31, 1995, the corporation's system of internal accounting controls is adequate to accomplish the objectives discussed herein.

The Board of Directors carries out its responsibility of financial overview through the Audit Committee of Enterprise, which presently consists of six directors who are not employees of Enterprise or any of its affiliates. The Enterprise Audit Committee meets periodically with management as well as with representatives of the internal auditors and Deloitte & Touche. The Audit Committee reviews the work of each to ensure that their respective responsibilities are being carried out and discusses related matters. Both the internal auditors and Deloitte & Touche, periodically meet alone with the Audit Committee and have free access to the Audit Committee, and its individual members, at any time.

**E. JAMES FERLAND**  
Chairman of the Board and  
Chief Executive Officer

**ROBERT C. MURRAY**  
Senior Vice President and  
Chief Financial Officer

**PATRICIA A. RADO**  
Vice President and Controller  
Principal Accounting Officer

February 14, 1996

## INDEPENDENT AUDITORS' REPORT

To the Stockholders and Board of Directors of  
Public Service Enterprise Group Incorporated:

We have audited the consolidated balance sheets of Public Service Enterprise Group Incorporated and its subsidiaries (the "Company") as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995. Our audits also included the consolidated financial statement schedules listed in the Index in Item 14(b)(1). These consolidated financial statements and the consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and consolidated financial statement schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Enterprise Group Incorporated and its subsidiaries at December 31, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We have also previously audited, in accordance with generally accepted auditing standards, the consolidated balance sheets as of December 31, 1993, 1992, and 1991, and the related consolidated statements of income, retained earnings and cash flows for the years ended December 31, 1992 and 1991 (none of which are presented herein) and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Selected Financial Data for each of the five years in the period ended December 31, 1995 for the Company, presented in Item 6, is fairly stated in all material respects, in relation to the consolidated financial statements from which it has been derived.

DELOITTE & TOUCHE LLP

February 14, 1996  
Parsippany, New Jersey

## **INDEPENDENT AUDITORS' REPORT**

To the Board of Directors of  
Public Service Electric and Gas Company:

We have audited the consolidated balance sheets of Public Service Electric & Gas Company and its subsidiaries (the "Company") as of December 31, 1995 and 1994, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 1995. Our audits also included the consolidated financial statement schedules listed in the Index in Item 14(b)(2). These consolidated financial statements and the consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and consolidated financial statement schedules based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Public Service Electric & Gas Company and its subsidiaries at December 31, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1995 in conformity with generally accepted accounting principles. Also, in our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

We have also previously audited, in accordance with generally accepted auditing standards, the consolidated balance sheets as of December 31, 1993, 1992, and 1991, and the related consolidated statements of income, retained earnings and cash flows for the years ended December 31, 1992 and 1991 (none of which are presented herein) and we expressed unqualified opinions on those consolidated financial statements. In our opinion, the information set forth in the Selected Financial Data for each of the five years in the period ended December 31, 1995 for the Company, presented in Item 6, is fairly stated in all material respects, in relation to the consolidated financial statements from which it has been derived.

DELOITTE & TOUCHE LLP

February 14, 1996  
Parsippany, New Jersey

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**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**CONSOLIDATED STATEMENTS OF INCOME**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
<b>OPERATING REVENUES</b>			
Electric .....	\$ 4,020,842	\$ 3,739,713	\$ 3,696,114
Gas .....	1,686,403	1,778,528	1,594,341
Nonutility Activities .....	456,908	404,202	418,135
Total Operating Revenues .....	6,164,153	5,922,443	5,708,590
<b>OPERATING EXPENSES</b>			
Operation			
Fuel for Electric Generation and Interchanged Power .....	891,782	695,763	717,136
Gas Purchased and Materials for Gas Produced .....	961,539	1,023,956	897,885
Other .....	1,118,758	1,118,523	1,014,455
Maintenance .....	312,610	308,080	304,403
Depreciation and Amortization .....	674,231	634,028	601,597
Property Impairment (note 16) .....	—	—	77,637
Taxes			
Federal Income Taxes (note 10) .....	353,997	312,551	313,680
New Jersey Gross Receipts Taxes .....	612,961	583,167	597,898
Other .....	80,565	82,282	77,052
Total Operating Expenses .....	5,006,443	4,758,350	4,601,743
OPERATING INCOME .....	1,157,710	1,164,093	1,106,847
<b>OTHER INCOME</b>			
Allowance for Funds Used During Construction — Equity .....	5,324	12,789	12,265
Miscellaneous — net .....	8,041	6,430	(3,778)
Total Other Income .....	13,365	19,219	8,487
<b>INCOME BEFORE INTEREST CHARGES AND DIVIDENDS ON PREFERRED SECURITIES</b> .....	1,171,075	1,183,312	1,115,334
<b>INTEREST CHARGES (note 6)</b>			
Long-Term Debt .....	434,066	459,158	469,120
Short-Term Debt .....	32,822	23,962	13,860
Other .....	29,172	12,805	19,554
Total Interest Charges .....	496,060	495,925	502,534
Allowance for Funds Used During Construction — Debt and Capitalized Interest .....	(37,208)	(33,793)	(20,833)
Net Interest Charges .....	458,852	462,132	481,701
Preferred Securities Dividend Requirements (note 4) .....	49,426	42,147	38,114
Preferred Stock Redemption Premium .....	474	—	—
Income before cumulative effect of accounting change .....	662,323	679,033	595,519
Cumulative effect of change in accounting for income taxes (note 10) ..	—	—	5,414
Net Income .....	\$ 662,323	\$ 679,033	\$ 600,933
<b>SHARES OF COMMON STOCK OUTSTANDING</b>			
End of Year .....	244,697,930	244,697,930	243,688,256
Average for Year .....	244,697,930	244,470,794	240,663,599
<b>EARNINGS PER AVERAGE SHARE OF COMMON STOCK</b>			
Before cumulative effect of accounting change .....	\$ 2.71	\$ 2.78	\$ 2.48
Cumulative effect of change in accounting for income taxes .....	—	—	.02
Total Earnings Per Average Share of Common Stock .....	\$ 2.71	\$ 2.78	\$ 2.50
<b>DIVIDENDS PAID PER SHARE OF COMMON STOCK</b> .....	\$ 2.16	\$ 2.16	\$ 2.16

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**CONSOLIDATED BALANCE SHEETS**

**ASSETS**

	December 31,	
	1995	1994
	(Thousands of Dollars)	
UTILITY PLANT—ORIGINAL COST (note 15)		
Electric .....	\$13,095,103	\$12,345,919
Gas .....	2,442,572	2,318,233
Common .....	517,104	545,131
Total .....	16,054,779	15,209,283
Less: accumulated depreciation and amortization .....	5,440,414	5,147,105
Net .....	10,614,365	10,062,178
Nuclear Fuel in Service, net of accumulated amortization—1995, \$297,435; 1994, \$302,906 .....	180,018	205,273
Net Utility Plant in Service .....	10,794,383	10,267,451
Construction Work in Progress, including Nuclear Fuel in Process—1995, \$104,743; 1994, \$65,429 .....	369,082	806,934
Plant Held for Future Use .....	23,966	23,860
Net Utility Plant .....	11,187,431	11,098,245
INVESTMENTS AND OTHER NONCURRENT ASSETS (notes 3, 7, 8, 11, 12 and 16)		
Long-Term Investments, net of amortization—1995, \$7,213; 1994, \$2,365, and net of valuation allowances—1995, \$21,302; 1994, \$17,104, respectively .....	1,822,160	1,625,952
Oil and Gas Property, Plant and Equipment, net of accumulated depreciation and amortization—1995, \$786,736; 1994, \$748,245 .....	608,015	577,913
Real Estate, Property and Equipment, net of accumulated depreciation—1995, \$5,063; 1994, \$14,242, and net of valuation allowances—1995, \$8,228; 1994, \$23,264, respectively .....	75,558	115,210
Other Plant, net of accumulated depreciation and amortization—1995, \$6,531; 1994, \$4,653 .....	27,997	36,063
Nuclear Decommissioning and Other Special Funds .....	276,348	233,022
Other Assets—net .....	55,974	85,478
Total Investments and Other Noncurrent Assets .....	2,866,052	2,673,638
CURRENT ASSETS		
Cash and Cash Equivalents (note 9) .....	76,233	67,866
Accounts Receivable:		
Customer Accounts Receivable .....	525,404	434,207
Other Accounts Receivable .....	260,713	211,779
Less: allowance for doubtful accounts .....	37,641	40,915
Unbilled Revenues .....	246,876	204,056
Fuel, at average cost .....	253,360	268,927
Materials and Supplies, net of inventory valuation reserves—1995, \$20,100; 1994, \$18,200, respectively ..	144,970	148,285
Deferred Income Taxes (note 10) .....	27,571	25,311
Miscellaneous Current Assets .....	62,631	37,356
Total Current Assets .....	1,560,117	1,356,872
DEFERRED DEBITS (note 5)		
Property Abandonments—net .....	70,120	88,269
Oil and Gas Property Write-Down .....	36,078	41,232
Unamortized Debt Expense .....	123,833	134,599
Deferred OPEB Costs (notes 1 and 13) .....	167,189	116,476
Underrecovered Electric Energy and Gas Costs—net .....	170,565	172,563
Unrecovered Environmental Costs (notes 2 and 12) .....	130,070	138,435
Unrecovered Plant and Regulatory Study Costs .....	35,150	37,128
Unrecovered SFAS 109 Deferred Income Taxes (note 10) .....	769,136	791,393
Deferred Decontamination and Decommissioning Costs (note 3) .....	49,872	53,016
Other .....	5,826	15,574
Total Deferred Debits .....	1,557,839	1,588,685
Total .....	\$17,171,439	\$16,717,440

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**CONSOLIDATED BALANCE SHEETS**  
**CAPITALIZATION AND LIABILITIES**

	December 31,	
	1995	1994
	(Thousands of Dollars)	
<b>CAPITALIZATION (notes 4 and 6)</b>		
Common Equity		
Common Stock .....	\$ 3,801,157	\$ 3,801,157
Retained Earnings .....	1,643,785	1,510,010
Total Common Equity .....	5,444,942	5,311,167
<b>SUBSIDIARIES' SECURITIES AND OBLIGATIONS</b>		
Preferred Securities		
Preferred Stock Without Mandatory Redemption .....	324,994	384,994
Preferred Stock With Mandatory Redemption .....	150,000	150,000
Monthly Income Preferred Securities .....	210,000	150,000
Long-Term Debt .....	5,189,791	5,180,657
Total Capitalization .....	11,319,727	11,176,818
<b>OTHER LONG-TERM LIABILITIES</b>		
Decontamination, Decommissioning and Low Level Radwaste Costs (note 3) .....	50,449	56,149
Environmental Costs (notes 2 and 12) .....	96,272	105,684
Capital Lease Obligations .....	53,111	53,770
Total Other Long-Term Liabilities .....	199,832	215,603
<b>CURRENT LIABILITIES</b>		
Long-Term Debt due within one year .....	90,630	499,738
Commercial Paper and Loans (note 6) .....	849,567	491,586
Book Overdrafts .....	70,014	86,576
Accounts Payable .....	567,787	433,471
Other Taxes Accrued .....	34,678	44,149
Interest Accrued .....	108,245	107,962
Estimated Liability for Vacation Pay .....	17,089	27,080
Customer Deposits .....	32,785	33,698
Liability for Injuries and Damages .....	38,141	29,814
Miscellaneous Environmental Liabilities .....	16,954	15,365
Other .....	95,907	87,480
Total Current Liabilities .....	1,921,797	1,856,919
<b>DEFERRED CREDITS</b>		
Accumulated Deferred Income Taxes (note 10) .....	3,094,620	2,905,390
Accumulated Deferred Investment Tax Credits .....	392,324	412,466
Deferred OPEB Costs (notes 1 and 13) .....	167,189	116,476
Other .....	75,950	33,768
Total Deferred Credits .....	3,730,083	3,468,100
<b>COMMITMENTS AND CONTINGENT LIABILITIES (note 12)</b>		
Total .....	\$17,171,439	\$16,717,440

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>			
Net Income .....	\$ 662,323	\$ 679,033	\$ 600,933
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and Amortization .....	674,231	634,028	601,597
Amortization of Nuclear Fuel .....	75,028	95,173	102,718
Recovery (Deferral) of Electric Energy and Gas Costs—net .....	1,998	(110,529)	(184,770)
Loss from Property Impairments .....	—	—	77,637
Cumulative Effect of Change in Accounting for Income Taxes .....	—	—	(5,414)
Unrealized Gains on Investments—net .....	(46,668)	(26,329)	(8,694)
Provision for Deferred Income Taxes—net .....	145,092	138,919	168,406
Investment Tax Credits—net .....	(20,142)	(20,247)	(11,655)
Allowance for Funds Used During Construction—Debt and Equity and Capitalized			
Interest .....	(42,532)	(46,582)	(33,098)
Proceeds from Leasing Activities—net .....	37,652	27,682	14,780
Changes in certain current assets and liabilities:			
Net (increase) decrease in Accounts Receivable and Unbilled Revenues .....	(186,225)	84,440	(68,382)
Net decrease in Inventory—Fuel and Materials and Supplies .....	18,882	41,169	16,438
Net increase (decrease) in Accounts Payable .....	134,316	(85,790)	95,331
Net decrease in Accrued Taxes .....	(17,279)	(258,818)	(293,919)
Net change in Other Current Assets and Liabilities .....	(12,005)	36,748	(19,505)
Other .....	68,244	42,893	(20,732)
Net cash provided by operating activities .....	<u>1,492,915</u>	<u>1,231,790</u>	<u>1,031,671</u>
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>			
Additions to Utility Plant, excluding AFDC .....	(649,883)	(849,174)	(863,294)
Additions to Oil and Gas Property, Plant and Equipment, excluding Capitalized Interest .....	(127,729)	(156,302)	(88,864)
Net (increase) decrease in Long-Term Investments and Real Estate .....	(81,264)	58,416	66,659
Increase in Decommissioning and Other Special Funds, excluding interest .....	(29,617)	(35,394)	(45,508)
Cost of Plant Removal—net .....	(29,674)	(33,962)	(47,791)
Other .....	29,899	13,933	(14,042)
Net cash used in investing activities .....	<u>(888,268)</u>	<u>(1,002,483)</u>	<u>(992,840)</u>
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>			
Net increase (decrease) in Short-Term Debt .....	357,981	(86,050)	185,654
(Decrease) increase in Book Overdrafts .....	(16,562)	23,584	(10,078)
Issuance of Long-Term Debt .....	156,320	849,800	2,137,700
Redemption of Long-Term Debt .....	(556,294)	(593,790)	(2,083,453)
Long-Term Debt Issuance and Redemption Costs .....	(9,177)	(29,811)	(72,114)
Issuance of Preferred Stock .....	—	75,000	75,000
Redemption of Preferred Stock .....	(60,000)	(120,000)	—
Issuance of Monthly Income Preferred Securities .....	60,000	150,000	—
Issuance of Common Stock .....	—	28,495	273,479
Cash Dividends Paid on Common Stock .....	(528,548)	(528,071)	(521,572)
Other .....	—	(1,970)	(6,772)
Net cash used in financing activities .....	<u>(596,280)</u>	<u>(232,813)</u>	<u>(22,156)</u>
Net increase (decrease) in Cash and Cash Equivalents .....	8,367	(3,506)	16,675
Cash and Cash Equivalents at Beginning of Year .....	67,866	71,372	54,697
Cash and Cash Equivalents at End of Year .....	<u>\$ 76,233</u>	<u>\$ 67,866</u>	<u>\$ 71,372</u>
Income Taxes Paid .....	\$ 185,376	\$ 155,104	\$ 140,172
Interest Paid .....	\$ 481,264	\$ 432,873	\$ 458,956

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**CONSOLIDATED STATEMENTS OF RETAINED EARNINGS**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
Balance January 1 .....	\$1,510,010	\$1,361,018	\$1,282,931
Add Net Income .....	662,323	679,033	600,933
Total .....	2,172,333	2,040,051	1,883,864
Deduct			
Dividends on Common Stock(A) .....	528,548	528,071	521,572
Capital Stock Expenses .....	—	1,970	1,274
Total Deductions .....	528,548	530,041	522,846
Balance December 31 .....	<u>\$1,643,785</u>	<u>\$1,510,010</u>	<u>\$1,361,018</u>

(A) The ability of Enterprise to declare and pay dividends is contingent upon its receipt of dividend payments from its subsidiaries. PSE&G, Enterprise's principal subsidiary, has restrictions on the payment of dividends which are contained in its Restated Certificate of Incorporation, as amended, certain of the indentures supplemental to its Mortgage and certain other indentures. However, none of these restrictions presently limits the payment of dividends out of current earnings. The amount of PSE&G's restricted retained earnings at December 31, 1995, 1994 and 1993 was \$10 million.

See Notes to Consolidated Financial Statements.

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**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**CONSOLIDATED STATEMENTS OF INCOME**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
<b>OPERATING REVENUES</b>			
Electric .....	\$4,020,842	\$3,739,713	\$3,696,114
Gas .....	1,686,403	1,778,528	1,594,341
<b>Total Operating Revenues</b> .....	<u>5,707,245</u>	<u>5,518,241</u>	<u>5,290,455</u>
<b>OPERATING EXPENSES</b>			
<b>Operation</b>			
Fuel for Electric Generation and Interchanged Power .....	891,782	695,763	717,136
Gas Purchased and Materials for Gas Produced .....	961,539	1,036,701	919,870
Other .....	949,400	959,859	882,641
<b>Maintenance</b> .....	312,610	308,080	304,403
<b>Depreciation and Amortization</b> .....	591,114	551,372	510,539
<b>Taxes</b>			
Federal Income Taxes (note 10) .....	321,433	294,529	308,790
New Jersey Gross Receipts Taxes .....	612,961	583,167	597,898
Other .....	70,904	76,100	67,593
<b>Total Operating Expenses</b> .....	<u>4,711,743</u>	<u>4,505,571</u>	<u>4,308,870</u>
<b>OPERATING INCOME</b> .....	<u>995,502</u>	<u>1,012,670</u>	<u>981,585</u>
<b>OTHER INCOME</b>			
Allowance for Funds Used During Construction — Equity .....	5,324	12,789	12,265
Miscellaneous — net .....	7,728	6,233	(3,841)
<b>Total Other Income</b> .....	<u>13,052</u>	<u>19,022</u>	<u>8,424</u>
<b>INCOME BEFORE INTEREST CHARGES AND DIVIDENDS ON PREFERRED SECURITIES</b> .....	<u>1,008,554</u>	<u>1,031,692</u>	<u>990,009</u>
<b>INTEREST CHARGES (note 6)</b>			
Long-Term Debt .....	357,584	366,894	364,252
Short-Term Debt .....	20,740	18,175	6,414
Other .....	28,545	10,856	19,290
<b>Total Interest Charges</b> .....	<u>406,869</u>	<u>395,925</u>	<u>389,956</u>
Allowance for Funds Used During Construction — Debt .....	(30,943)	(25,319)	(14,815)
<b>Net Interest Charges</b> .....	<u>375,926</u>	<u>370,606</u>	<u>375,141</u>
Monthly Income Preferred Securities Dividend Requirements (note 4) ..	15,664	1,680	—
<b>Net Income</b> .....	<u>616,964</u>	<u>659,406</u>	<u>614,868</u>
Preferred Stock Dividend Requirements (note 4) .....	33,762	40,467	38,114
Preferred Stock Redemption Premium (note 4) .....	474	—	—
<b>EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED</b> .....	<u>\$ 582,728</u>	<u>\$ 618,939</u>	<u>\$ 576,754</u>

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**CONSOLIDATED BALANCE SHEETS**  
**ASSETS**

	December 31,	
	1995	1994
	(Thousands of Dollars)	
UTILITY PLANT—ORIGINAL COST (note 15)		
Electric .....	\$13,095,103	\$12,345,919
Gas .....	2,442,572	2,318,233
Common .....	517,104	545,131
Total .....	16,054,779	15,209,283
Less accumulated depreciation and amortization .....	5,440,414	5,147,105
Net .....	10,614,365	10,062,178
Nuclear Fuel in Service, net of accumulated amortization—1995, \$297,435; 1994, \$302,906 .....	180,018	205,273
Net Utility Plant in Service .....	10,794,383	10,267,451
Construction Work in Progress, including Nuclear Fuel in Process—1995, \$104,743; 1994, \$65,429 ..	369,082	806,934
Plant Held for Future Use .....	23,966	23,860
Net Utility Plant .....	11,187,431	11,098,245
INVESTMENTS AND OTHER NONCURRENT ASSETS		
Long-Term Investments, net of amortization—1995, \$6,009; 1994, \$2,365, respectively .....	119,474	65,886
Nuclear Decommissioning and Other Special Funds (note 3) .....	276,348	233,022
Other Plant, net of accumulated depreciation and amortization—1995, \$1,905; 1994, \$1,127 .....	24,976	32,879
Total Investments and Other Noncurrent Assets .....	420,798	331,787
CURRENT ASSETS		
Cash and Cash Equivalents (note 9) .....	32,373	27,498
Accounts Receivable:		
Customer Accounts Receivable .....	525,404	434,207
Other Accounts Receivable .....	163,976	151,684
Less: allowance for doubtful accounts .....	37,641	40,915
Unbilled Revenues .....	246,876	204,056
Fuel, at average cost .....	253,360	268,927
Materials and Supplies, net of inventory valuation reserves—1995, \$20,100; 1994, \$18,200, respectively .....	143,741	146,763
Deferred Income Taxes (note 10) .....	27,571	25,311
Miscellaneous Current Assets .....	37,130	30,407
Total Current Assets .....	1,392,790	1,247,938
DEFERRED DEBITS (note 5)		
Property Abandonments—net .....	70,120	88,269
Oil and Gas Property Write-Down .....	36,078	41,232
Unamortized Debt Expense .....	122,049	132,342
Deferred OPEB Costs (notes 1 and 13) .....	167,189	116,476
Underrecovered Electric Energy and Gas Costs—net .....	170,565	172,563
Unrecovered Environmental Costs (notes 2 and 12) .....	130,070	138,435
Unrecovered Plant and Regulatory Study Costs .....	35,150	37,128
Deferred Decontamination and Decommissioning Costs (note 3) .....	49,872	53,016
Unrecovered SFAS 109 Deferred Income Taxes (note 10) .....	769,136	791,393
Other .....	5,700	15,574
Total Deferred Debits .....	1,555,929	1,586,428
Total .....	\$14,556,948	\$14,264,398

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**CONSOLIDATED BALANCE SHEETS**  
**CAPITALIZATION AND LIABILITIES**

	December 31,	
	1995	1994
	(Thousands of Dollars)	
CAPITALIZATION (notes 4 and 6)		
Common Equity		
Common Stock .....	\$ 2,563,003	\$ 2,563,003
Contributed Capital from Enterprise .....	594,395	534,395
Retained Earnings .....	1,372,729	1,292,201
Total Common Equity .....	4,530,127	4,389,599
Preferred Stock without mandatory redemption .....	324,994	384,994
Preferred Stock with mandatory redemption .....	150,000	150,000
Monthly Income Preferred Securities of Subsidiary .....	210,000	150,000
Long-Term Debt .....	4,586,268	4,486,787
Total Capitalization .....	9,801,389	9,561,380
OTHER LONG-TERM LIABILITIES		
Decontamination, Decommissioning and Low Level Radwaste Costs (note 3) .....	50,449	56,149
Environmental Costs (notes 2 and 12) .....	96,272	105,684
Capital Lease Obligations (note 11) .....	53,111	53,770
Total Other Long-Term Liabilities .....	199,832	215,603
CURRENT LIABILITIES		
Long-Term Debt due within one year .....	—	310,200
Commercial Paper and Loans (note 6) .....	567,316	401,759
Book Overdrafts .....	70,014	86,576
Accounts Payable .....	481,632	370,005
Accounts Payable—Associated Companies (note 19) .....	8,011	16,677
Other Taxes Accrued .....	32,767	36,030
Interest Accrued .....	95,811	95,721
Estimated Liability for Vacation Pay .....	17,089	27,080
Customer Deposits .....	32,785	33,698
Liability for Injuries and Damages .....	38,141	29,814
Miscellaneous Environmental Liabilities .....	16,954	15,365
Other .....	50,751	50,778
Total Current Liabilities .....	1,411,271	1,473,703
DEFERRED CREDITS		
Accumulated Deferred Income Taxes (note 10) .....	2,535,603	2,478,539
Accumulated Deferred Investment Tax Credits .....	370,610	389,721
Deferred OPEB Costs (notes 1 and 13) .....	167,189	116,476
Other .....	71,054	28,976
Total Deferred Credits .....	3,144,456	3,013,712
COMMITMENTS AND CONTINGENT LIABILITIES (note 12)		
Total .....	\$14,556,948	\$14,264,398

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>			
Net Income .....	\$ 616,964	\$ 659,406	\$ 614,868
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and Amortization .....	591,114	551,372	510,539
Amortization of Nuclear Fuel .....	75,028	95,173	102,718
Recovery (Deferral) of Electric Energy and Gas Costs—net .....	1,998	(110,529)	(184,770)
Provision for Deferred Income Taxes—net .....	79,321	108,163	175,868
Investment Tax Credits—net .....	(19,111)	(19,208)	(18,408)
Allowance for Funds Used During Construction—Debt and Equity .....	(36,267)	(38,108)	(27,080)
Changes in certain current assets and liabilities:			
Net (increase) decrease in Accounts Receivable and Unbilled Revenues .....	(149,583)	74,891	(78,953)
Net decrease in Inventory—Fuel and Materials and Supplies .....	18,589	41,163	16,920
Net increase (decrease) in Accounts Payable .....	102,961	(99,788)	83,421
Net decrease in Accrued Taxes .....	(11,071)	(261,037)	(286,119)
Net change in Other Current Assets and Liabilities .....	(2,100)	36,245	(27,790)
Other .....	57,158	22,763	(49,006)
Net cash provided by operating activities .....	<u>1,325,001</u>	<u>1,060,506</u>	<u>832,208</u>
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>			
Additions to Utility Plant, excluding AFDC .....	(649,883)	(849,174)	(863,294)
Net (increase) decrease in Long-Term Investments .....	(65,189)	50,668	(26,980)
Net increase in Decommissioning Funds and Other Special Funds, excluding interest ..	(29,617)	(35,394)	(45,508)
Cost of Plant Removal—net .....	(29,674)	(33,962)	(47,791)
Other .....	859	1,692	(13,607)
Net cash used in investing activities .....	<u>(773,504)</u>	<u>(866,170)</u>	<u>(997,180)</u>
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>			
Net increase (decrease) in Short-Term Debt .....	165,557	(130,969)	275,192
(Decrease) increase in Book Overdrafts .....	(16,562)	23,584	(10,078)
Issuance of Long-Term Debt .....	156,320	849,800	1,972,700
Redemption of Long-Term Debt .....	(367,039)	(478,950)	(1,716,401)
Long-Term Debt Issuance and Redemption Costs .....	(8,462)	(29,731)	(68,227)
Issuance of Preferred Stock .....	—	75,000	75,000
Redemption of Preferred Stock .....	(60,000)	(120,000)	—
Issuance of Monthly Income Preferred Securities .....	60,000	150,000	—
Contributed Capital by Enterprise .....	60,000	—	174,670
Cash Dividends Paid .....	(535,962)	(545,767)	(531,314)
Other .....	(474)	(1,970)	(754)
Net cash (used in) provided by financing activities .....	<u>(546,622)</u>	<u>(209,003)</u>	<u>170,788</u>
Net increase (decrease) in Cash and Cash Equivalents .....	4,875	(14,667)	5,816
Cash and Cash Equivalents at Beginning of Year .....	27,498	42,165	36,349
Cash and Cash Equivalents at End of Year .....	<u>\$ 32,373</u>	<u>\$ 27,498</u>	<u>\$ 42,165</u>
Income Taxes Paid .....	\$ 279,873	\$ 209,196	\$ 172,869
Interest Paid .....	\$ 399,509	\$ 345,867	\$ 356,620

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**CONSOLIDATED STATEMENTS OF RETAINED EARNINGS**

	For the Years Ended December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
Balance January 1 .....	\$1,292,201	\$1,180,532	\$1,097,734
Add Net Income .....	616,964	659,406	614,868
Total .....	<u>1,909,165</u>	<u>1,839,938</u>	<u>1,712,602</u>
Deduct Cash Dividends(A)			
Preferred Stock, at required rates .....	33,762	40,467	38,114
Common Stock .....	502,200	505,300	493,200
Adjustment to Retained Earnings .....	474	1,970	756
Total Deductions .....	<u>536,436</u>	<u>547,737</u>	<u>532,070</u>
Balance December 31 .....	<u>\$1,372,729</u>	<u>\$1,292,201</u>	<u>\$1,180,532</u>

- (A) The Company has restrictions on the payment of dividends which are contained in its Restated Certificate of Incorporation, as amended, and certain of the indentures supplemental to its Mortgage and certain other indentures. However, none of these restrictions presently limits the payment of dividends out of current earnings. The amount of the Company's restricted retained earnings at December 31, 1995, 1994 and 1993 was \$10 million.

See Notes to Consolidated Financial Statements.

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**Note 1. Organization and Summary of Significant Accounting Policies**

**Organization**

Public Service Enterprise Group (Enterprise) has two direct wholly owned subsidiaries, Public Service Electric and Gas Company (PSE&G) and Enterprise Diversified Holdings Incorporated (EDHI). Enterprise's principal subsidiary, PSE&G, is an operating public utility providing electric and gas service to customers in certain areas in the State of New Jersey. As of December 31, 1995, PSE&G comprised 85% of Enterprise's assets and for the year ending on that date, 93% of its revenues. Of the 150,000,000 authorized shares of PSE&G common stock at December 31, 1995, there were 132,450,344 shares outstanding, with an aggregate book value of \$2.6 billion.

PSE&G has a finance subsidiary, PSE&G Fuel Corporation (Fuelco), providing financing, unconditionally guaranteed by PSE&G, of up to \$150 million aggregate principal amount at any one time of a 42.49% interest in the nuclear fuel acquired for Peach Bottom Atomic Power Station Units 2 and 3 (Peach Bottom). PSE&G also has a subsidiary, Public Service Conservation Resources Corporation (PSCRC) which offers demand side management (DSM) services to utility customers. In 1994, Public Service Electric and Gas Capital, L.P. (Partnership), a limited partnership in which PSE&G is the general partner, was formed for the purpose of issuing Monthly Income Preferred Securities. (See Note 4—Schedule of Consolidated Capital Stock and Other Securities). In 1995, PSE&G created a new subsidiary, Enterprise Ventures and Services, to pursue products and services beyond traditional geographic and industry boundaries.

EDHI is the parent of Enterprise's nonutility businesses: Energy Development Corporation (EDC), an oil and gas exploration and production and marketing company; Community Energy Alternatives Incorporated (CEA), an investor in and developer and operator of cogeneration and independent power production facilities; Public Service Resources Corporation (PSRC), which makes primarily passive investments; and Enterprise Group Development Corporation (EGDC), a nonresidential real estate development and investment business. EDHI also has two finance subsidiaries: PSEG Capital Corporation (Capital) and Enterprise Capital Funding Corporation (Funding).

**Consolidation Policy**

The consolidated financial statements include the accounts of Enterprise and its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain reclassifications of prior years' data have been made to conform with the current presentation.

**Regulation—PSE&G**

The accounting and rates of PSE&G are subject, in certain respects, to the requirements of the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). As a result, PSE&G maintains its accounts in accordance with their prescribed Uniform Systems of Accounts, which are the same. The applications of Generally Accepted Accounting Principles (GAAP) by PSE&G differ in certain respects from applications by non-regulated businesses. PSE&G prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards No. 71—"Accounting for the Effects of Certain Types of Regulation" (SFAS 71). In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the relationship of costs and revenues. As a result, a regulated utility may defer recognition of cost (a regulatory asset) or recognize an obligation (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in revenues. Accordingly, PSE&G has deferred certain costs, which will be amortized over various periods. To the extent that collection of such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or PSE&G's competitive position, the associated regulatory asset or liability will be reversed with a charge or credit to income. (See Note

## **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

5—Deferred Items). If PSE&G were to discontinue the application of SFAS 71, the accounting impact would be an extraordinary, non-cash charge to operations that could be material to the financial position and results of operations of Enterprise and PSE&G.

Amounts charged to operations for depreciation expense reflect estimated useful lives and methods, which include estimates of cost of removal and salvage, prescribed and approved by regulators rather than those that might otherwise apply to non-regulated enterprises. PSE&G cannot presently quantify what the financial statement impact may be if depreciation expense were to be determined absent regulation.

### **Utility Plant and Related Depreciation—PSE&G**

Additions to utility plant and replacements of units of property are capitalized at original cost. The cost of maintenance, repairs and replacements of minor items of property is charged to appropriate expense accounts. At the time units of depreciable property are retired or otherwise disposed of, the original cost less net salvage value is charged to accumulated depreciation.

Depreciation is computed under the straight-line method. Depreciation is based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU. Depreciation provisions stated in percentages of original cost of depreciable property were 3.52% in 1995, 3.51% in 1994 and 3.46% in 1993.

### **Use of Estimates**

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

### **Decontamination and Decommissioning—PSE&G**

In 1993, FERC issued Order No. 557 on the accounting and rate-making treatment of special assessments levied under the National Energy Policy Act of 1992 (EPAct). Order No. 557 provides that special assessments are a necessary and reasonable current cost of fuel and shall be fully recoverable in rates in the same manner as other fuel costs. In accordance with its filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies, but no assurances can be given that the BPU will authorize such recovery from customers. (See Note 2—Rate Matters and Note 3—PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel—Uranium, Decontamination and Decommissioning Fund).

### **Amortization of Nuclear Fuel—PSE&G**

Nuclear energy burnup costs are charged to fuel expense on a units-of-production basis over the estimated life of the fuel. Rates for the recovery of fuel used at all nuclear units include a provision of one mill per kilowatthour (KWH) of nuclear generation for spent fuel disposal costs. (See Note 3—PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel).

### **Revenues and Fuel Costs—PSE&G**

Revenues are recorded based on services rendered to customers during each accounting period. PSE&G records unbilled revenues representing the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. Rates include projected fuel costs for electric generation, purchased and interchanged power, gas purchased and materials used for gas production.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Any under or overrecoveries, together with interest (in the case of net overrecoveries), are deferred and included in operations in the period in which they are reflected in rates.

### Long-Term Investments

PSRC has invested in securities and limited partnerships investing in securities, which are recorded at fair value, and various leases and other limited partnerships. EGDC is a participant in the nonresidential real estate markets. CEA is an investor in and developer and operator of cogeneration and power production facilities. (See Note 7—Long-Term Investments).

### Derivatives

Gains and losses on hedges of existing assets or liabilities are included in the carrying amounts of those assets and liabilities and are ultimately recognized in income as part of those carrying amounts. Gains and losses related to qualifying hedges of firm commitments or anticipated transactions also are deferred and recognized in income or as adjustments of carrying amounts when the hedged transaction occurs. (See Note 8—Financial Instruments and Risk Management).

### Oil and Gas Accounting—EDC

EDC uses the successful efforts method of accounting under which proved leasehold costs are capitalized and amortized over the proved developed and undeveloped reserves on a unit-of-production basis. Drilling and equipping costs, except exploratory dry holes, are capitalized and depreciated over the proved developed reserves on a unit-of-production basis. Estimated future abandonment costs of offshore proved properties are depreciated on a unit-of-production basis over the proved developed reserves. Estimated future abandonment costs of onshore properties are estimated to be offset by the salvage value of the tangible equipment. Unproved leasehold costs are capitalized and not amortized, pending an evaluation of the exploration results. Unproved leasehold and producing properties costs are assessed periodically to determine if an impairment of the cost of significant individual properties has occurred. The cost of an impairment is charged to expense. Costs incurred for exploratory dry holes, exploratory geological and geophysical work and delay rentals are charged to expense as incurred.

### Income Taxes

Enterprise and its subsidiaries file a consolidated Federal income tax return and income taxes are allocated to Enterprise's subsidiaries based on taxable income or loss of each. Investment tax credits are deferred and amortized over the useful lives of the related property, including nuclear fuel.

Effective January 1, 1993, Enterprise and its subsidiaries adopted Statement of Financial Accounting Standards No. 109 "Accounting for Income Taxes" (SFAS 109). Under SFAS 109, deferred income taxes are provided for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. For periods prior to January 1, 1993, PSE&G provided deferred income taxes to the extent permitted for rate-making purposes. (See Note 10—Federal Income Taxes).

### Allowance for Funds Used During Construction (AFDC) and Capitalized Interest

PSE&G—AFDC represents the cost of debt and equity funds used to finance the construction of new utility facilities. The amount of AFDC capitalized is reported in the Consolidated Statements of Income as a reduction of interest charges for the borrowed funds component and as other income for the equity funds component. The rates used for calculating AFDC in 1995, 1994 and 1993 were 6.98%, 6.48% and 6.96%, respectively. These rates were within the limits set by FERC.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

EDHI—The operating subsidiaries of EDHI capitalize interest costs allocable to construction expenditures at the average cost of borrowed funds.

### Pension Plan and Other Postretirement Benefits

The employees of PSE&G, other than non represented employees commencing service after January 1, 1996, as well as those of participating affiliates, are covered by a noncontributory trustee pension plan (Pension Plan) from the date of hire. New represented employees of PSE&G who commence service after January 1, 1996 are covered by a Cash Balance Pension Plan. The policy is to fund pension costs accrued. PSE&G also provides certain health care and life insurance benefits to active and retired employees. The portion of such costs pertaining to retirees amounted to \$33 million, \$29 million, and \$28 million in 1995, 1994 and 1993, respectively. The current cost of these benefits is charged to expense when paid and is currently being recovered from ratepayers.

On January 1, 1993, Enterprise and PSE&G adopted Statement of Financial Accounting Standards No. 106, "Employers Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106), which requires that the expected cost of employees' postretirement health care benefits be charged to expense during the years in which employees render service. Prior to 1993, Enterprise and PSE&G recognized postretirement health care costs in the year in which the benefits were paid. PSE&G elected to amortize over 20 years its unfunded obligation at January 1, 1993. (See Note 13—Postretirement Benefits Other Than Pensions and Note 14—Pension Plan).

### Note 2. Rate Matters

#### Alternative Rate Plan

On January 16, 1996, PSE&G proposed to the BPU major changes in utility regulation that include an immediate \$50 million rate reduction for its electric customers, various types of rate freezes, assurances that future price increases related to controllable costs will be lower than the rate of inflation and funding of up to an aggregate of \$55 million in two economic development initiatives.

The seven-year "New Jersey Partners in Power" Plan (Plan), if approved, would give PSE&G the mechanisms and incentives to compete more effectively on several fronts, including the ability to develop revenue from non-regulated products and services, accelerate or modify depreciation schedules to help mitigate any potential stranded asset issue and more aggressively manage the control of costs. In addition, the Plan would provide the foundation for ongoing price flexibility without the need for prolonged, adversarial regulatory proceedings.

The Plan begins the process for a transition to a more competitive energy marketplace while substantially shifting the business and financial risks and opportunities involved in this transition away from customers to PSE&G and enhancing PSE&G's ability to make the necessary human, intellectual and financial investments required to stimulate innovation and productivity.

Key energy pricing features of the proposed Plan are as follows:

Upon the BPU's approval of the Plan, PSE&G will reduce electric rates across the board by \$50 million annually as an upfront guaranteed share of the productivity improvements that it expects to achieve over the life of the Plan.

New rates for all PSE&G electric customers reflecting the reduction would be established through a merger of existing base tariffs and the electric Levelized Energy Adjustment Clause (LEAC) and would be frozen at these levels through December 31, 1996. In addition, the Plan proposes the elimination of the BPU's existing Nuclear Performance Standard (NPS). This discontinuance of the LEAC and NPS would result in substantially

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

shifting the risks and opportunities involved in managing changes in fuel and replacement power costs from customers to PSE&G. Gas fuel costs will continue to be recovered on a dollar for dollar basis from customers under the existing Levelized Gas Adjustment Charge (LGAC).

In order to create incentives to lower costs and improve efficiency and productivity, the Plan would rely on a comprehensive external price cap index based upon changes in the Gross Domestic Product Price Index (GDPPPI) and a separate fuel price index mechanism, reduced by a fixed productivity offset of 0.30% to establish optional annual price changes each January 1st for electricity. In addition, the Plan would rely on an index for non-fuel gas prices calculated on the basis of changes in the GDPPPI, reduced by a fixed productivity offset of 0.35%, to establish optional annual price changes each January 1st. The price cap mechanisms would become effective on January 1, 1997 and would assure that any rate increase related to controllable costs would be below the rate of inflation, guaranteeing that these costs would decline in real terms.

Under the Plan, PSE&G would establish an initial service block equal to the first 150 kilowatthours (KWH) of usage for residential electric customers who would be protected from price cap index increases through December 31, 2002, the proposed expiration date of the Plan. Similarly, an initial service block equal to 40 therms would be set for residential gas customers and protected from index increases over the same period of time. In addition, public street lighting prices would not be subject to index increases for the life of the Plan.

The Plan includes a productivity gains sharing mechanism. This mechanism has been designed to provide incentives to maximize efficiency and productivity improvements and ensure that electric and gas customers receive an increasing share of productivity gains using returns on equity as a proxy for these gains. The gains, which would be awarded through bill credits, would be based on a threshold earnings level defined as PSE&G's established return on equity of 12% plus a 100 basis points neutral zone above that level. Customers would receive a 10% share of the gains from the first 50 basis points above the threshold level. Their share would increase by an additional 10% for each subsequent increase of 50 basis points up to a maximum of 50%.

Separate mechanisms also would be established to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies or otherwise out of PSE&G's control. These costs include demand side management programs, environmental remediation, costs associated with non-utility electric generators, nuclear decommissioning funding and nuclear fuel assessment costs. These mechanisms would assure that PSE&G recovers only actual costs related to these activities.

The Plan would allow for electric and non-fuel gas prices to be changed to reflect exogenous events beyond the control of PSE&G and would be subject to modification for industry restructuring.

The Plan calls for an increase of \$50 million in annual depreciation expenses for PSE&G's Hope Creek nuclear generating station—\$25 million effective January 1, 1997, and an additional \$25 million effective January 1, 1998. In addition, the Plan proposes a transfer of depreciation reserves totaling \$253 million from transmission and distribution to fossil steam electric generating accounts. The Plan would permit depreciation to be changed annually following BPU review and approval.

In addition to the pricing features, the Plan guarantees enhanced quality of customer services through PSE&G's recently established service guarantee program for electric and gas customers and specific incentive and penalty mechanisms based on various service indicators.

The Plan would establish a program of rewards and penalties in key overall service indicators such as duration of customer power outages compared to a historic five-year average.

In addition to these service quality incentives, the Plan would establish rewards and penalties based on the movement of PSE&G's average electric residential rate measured against the national average of residential

## **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

electric rates. Rewards or penalties of up to \$5 million would be implemented if comparisons indicate that PSE&G's residential rates decreased or increased by more than one-half of one percent relative to the national average.

A major component of the Plan is a proposed economic and market development and retention assurance program. This would allow flexible pricing and promote special economic development activities designed to enhance the economic vitality of the State of New Jersey. One aspect of the program would give PSE&G the ability to quickly establish new optional electric or gas rates or individual customer contracts to serve new markets and retain or attract individual customers.

Also under the Plan, PSE&G would fund two economic development initiatives. The first is a private sector leadership investment of \$5 million in the New Jersey Fund for Community Economic Development. The second new initiative is the establishment of the PSE&G Economic Development Fund in which PSE&G would commit to investing up to \$50 million for financing significant economic development projects within PSE&G's service territory over the seven years of the Plan.

In addition, the Plan calls for establishment of a State Emissions Trading Bank (Bank) for economic development and environmental improvement. PSE&G would donate 1,000 tons of nitrogen oxide emissions credits to the Bank for use in economic development. This is intended as a key step to linking economic development with sound environmental policy and building on New Jersey's leadership role in seeking a regional solution to air pollution problems.

Under the Plan, price levels associated with the recovery of Gross Receipts and Franchise Tax (GRFT) or successor taxes will be directly adjusted in such a manner as to insure their full and timely recovery from ratepayers.

PSE&G cannot predict what action, if any, may be taken by the BPU with respect to the Plan.

### **Levelized Gas Adjustment Charge**

On October 2, 1995, PSE&G petitioned the BPU for modifications to its LGAC, requesting that:

- (a) The LGAC be renamed to the Levelized Gas Incentive Clause (LGIC);
- (b) A benchmark be established for certain gas delivered from the Gulf Coast, and any difference between PSE&G's actual gas purchase costs and the benchmark price, either positive or negative, be shared 50/50 between customers and PSE&G;
- (c) The current annual LGAC rate be converted to a monthly rate for firm commercial and industrial customers; and
- (d) A fixed annual margin would be credited to LGAC for certain interruptible rate schedules, while actual margins from such sales will be retained by PSE&G. Any differences, positive or negative, will be absorbed by PSE&G.

On December 20, 1995, the BPU approved an interim Stipulation to include the implementation of monthly pricing on the commodity portion of the LGAC rate for firm commercial and industrial customers effective January 1, 1996. The incentive proposal relating to interruptible sales (request (d)) above was withdrawn. The remaining aspects of PSE&G's October 2, 1995 petition remain the subject of continued investigation and litigation.

### **Electric Levelized Energy Adjustment Clause**

By Order dated May 5, 1995, the BPU approved PSE&G's LEAC. Such Order also required that a hearing be convened regarding the April 1994 Salem 1 shutdown, to determine whether PSE&G should be allowed to

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

recover replacement power costs of approximately \$8 million which have been deferred. On October 18, 1995, this matter was ordered to be transmitted to the Office of Administrative Law (OAL) for hearing. PSE&G cannot predict the outcome of this proceeding.

### **Remediation Adjustment Charge**

On July 21, 1995, PSE&G petitioned the BPU to recover Remediation Program costs incurred during the period August 1, 1994 through July 31, 1995. In accordance with a BPU Order dated November 4, 1994, the petition proposes to recover, effective October 1, 1995, \$2.5 million from gas customers and \$1.6 million from electric customers.

### **Consolidated Tax Benefits**

In a case affecting another utility in which neither Enterprise nor PSE&G were parties, the BPU considered the extent to which tax savings generated by nonutility affiliates included in the consolidated tax return of that utility's holding company should be considered in setting that utility's rates. In September, 1992, the BPU approved an order in such case treating certain consolidated tax savings generated after June 30, 1990 by that utility's nonutility affiliates as a reduction of its rate base. In December, 1992, the BPU issued an order approving a stipulation in PSE&G's 1992 base rate proceeding which resolved the case without separate quantification of the consolidated tax issue. The stipulation did not provide final resolution of the consolidated tax issue for any subsequent base rate filing. While Enterprise continues to account for its two wholly-owned subsidiaries on a stand-alone basis, resulting in a realization of the tax benefits by the entity generating the benefit, an ultimate unfavorable resolution of the consolidated tax issue could reduce PSE&G's and Enterprise's future revenue and net income. In addition, an unfavorable resolution may adversely impact Enterprise's nonutility investment strategy. Enterprise believes that PSE&G's taxes should be treated on a stand-alone basis for rate-making purposes, based on the separate nature of the utility and nonutility businesses. However, neither Enterprise nor PSE&G is able to predict what action, if any, the BPU may take concerning consolidation of tax benefits in future rate proceedings. (See Note 10—Federal Income Taxes).

### **Other Rate Matters**

On July 21, 1995, the BPU initiated a generic proceeding to expeditiously adopt specific standards to guide utility "off-tariff" negotiated rate agreement programs, which proceeding would consider minimum prices, confidentiality, maximum contract duration, filing requirements and such other standards as necessary for compliance with the law. A Written Summary Decision and Order was issued on October 27, 1995, which ordered each New Jersey electric utility, including PSE&G, to file initial minimum tariffs, consistent with the terms of such Order, and further, indicated that such Order will be supplemented by a Final Decision and Order to fully discuss and explain the rationale for the BPU's overall decision. On November 13, 1995 PSE&G filed its compliance filing. PSE&G cannot predict what impact, if any, the generic tariff may have on its electric revenues and earnings.

In September 1994, the BPU initiated a generic proceeding regarding recovery of capacity costs associated with electric utility power purchases from cogeneration and small power producers. The initial phase of the proceeding, which has been transmitted to the Office of Administrative Law, seeks to determine whether there was any such overrecovery and, if so, the amount overrecovered.

The New Jersey Division of Ratepayer Advocate has intervened in the proceeding and alleges, among other things, that PSE&G has overrecovered such costs ranging from \$250 to \$300 million during the period from August 1991 to December 1994. PSE&G denies such overrecovery because its capacity cost recovery mechanisms were approved by the BPU as to each of its cogeneration contracts and as to its base rates. Additionally, PSE&G contends that a review of any individual cost item is inappropriate and that the BPU has

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

previously found that, during the period under review, PSE&G did not overearn compared to its established return. Moreover, PSE&G contends that the Ratepayer Advocate's assertion is proscribed as retroactive ratemaking.

While PSE&G cannot predict the outcome of this proceeding, the final resolution of this issue may impact the financial position, results from operations or net cash flows of Enterprise and PSE&G on a prospective basis.

### **Note 3. PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel**

The BPU decision in PSE&G's 1992 base rate case utilized studies based on the prompt removal/dismantlement method of decommissioning for all of PSE&G's nuclear generating stations. This method consists of removing all fuel, source material and all other radioactive materials with activity levels above accepted release limits from the nuclear sites. PSE&G has an ownership interest in five nuclear units: Salem 1 and Salem 2—42.59% each, Hope Creek—95% and Peach Bottom 2 and 3—42.49% each. In accordance with rate orders received from the BPU, PSE&G has established an external master nuclear decommissioning trust for all of its nuclear units. The Internal Revenue Service (IRS) has ruled that payments to the trust are tax deductible. PSE&G's total estimated cost of decommissioning its share of these 5 nuclear units is estimated at \$681 million in year-end 1990 dollars (the year that the site specific estimate was prepared), excluding contingencies. The 1992 base rate decision provided that \$15.6 million of such costs are to be collected through base rates and an additional annual amount of \$7.0 million in 1993 and \$14 million each year thereafter are to be recovered through PSE&G's LEAC. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies, but no assurances can be given that the BPU will authorize such recovery from customers. (See Note 2—Rate Matters). At December 31, 1995 and 1994, the accumulated provision for depreciation and amortization included reserves for nuclear decommissioning for PSE&G's units of \$292 million and \$249 million, respectively. As of December 31, 1995 and 1994, PSE&G had contributed \$220 million and \$190 million, respectively, into independent external qualified and nonqualified nuclear decommissioning trust funds.

On January 3, 1996, PSE&G filed with the BPU its 1995 nuclear plant decommissioning cost update. The filing includes decommissioning cost updates for PSE&G's respective ownership share of Salem, Hope Creek and Peach Bottom. PSE&G's filing was based on the existing Nuclear Regulatory Commission (NRC) generic formula(s). PSE&G does not believe that the NRC generic estimates provide an accurate estimate of the cost of decommissioning because the NRC formula does not factor into its cost estimates the cost of removal of nonradiological structures and equipment and interim spent fuel storage installations. PSE&G is currently completing site specific studies in order to update its filing with the BPU during 1996.

The Staff of the Securities and Exchange Commission (SEC) has questioned certain of the current accounting practices of the electric utility industry, including PSE&G, regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the Financial Accounting Standards Board (FASB) has agreed to review the accounting for removal costs, including decommissioning. If current electric utility industry accounting practices for such decommissioning are changed: (1) annual provisions for decommissioning could increase, (2) the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation and (3) trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

### **Uranium Enrichment Decontamination and Decommissioning Fund**

In accordance with EPAct, domestic utilities that own nuclear generating stations are required to pay a cumulative total of \$150 million each year (adjusted for inflation) into a decontamination and decommissioning

## **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

fund, based on their past purchases of enrichment services from the United States Department of Energy (DOE) Uranium Enrichment Enterprise (now a federal government corporation known as the United States Enrichment Corporation (USEC)). These amounts are being collected over a period of 15 years or until \$2.25 billion (adjusted for inflation) has been collected. Under this legislation, PSE&G's obligation for the nuclear generating stations in which it has an interest is \$67 million (adjusted for inflation). Since 1993, PSE&G has paid \$17 million, resulting in a balance due of \$50 million. PSE&G has deferred the expenditures incurred to date as part of deferred underrecovered electric energy costs and expects to recover its costs in the next LEAC. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies, but no assurances can be given that the BPU will authorize such recovery from customers. (See Note 2—Rate Matters).

### **Spent Nuclear Fuel Disposal Costs**

In accordance with the Nuclear Waste Policy Act (NWPA), PSE&G has entered into contracts with the DOE for the disposal of spent nuclear fuel. Payments made to the DOE for disposal costs are based on nuclear generation and are included in Fuel for Electric Generation and Interchanged Power in the Statements of Income. These costs are recovered through the LEAC. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies, but no assurances can be given that the BPU will authorize such recovery from customers. (See Note 2—Rate Matters).

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## **Note 4. Schedule of Consolidated Capital Stock and Other Securities**

	<u>Outstanding Shares</u>	<u>Current Redemption Price Per Share</u>	<u>December 31, 1995</u>	<u>December 31, 1994</u>
			<u>(Thousands of Dollars)</u>	
Enterprise Common Stock (no par)—(note A)— Authorized 500,000,000 shares; issued and outstanding at December 31, 1995, and December 31, 1994, 244,697,930 shares, and at December 31, 1993, 243,688,256 shares .....			\$3,801,157	\$3,801,157
Enterprise Preferred Securities (note B) PSE&G Cumulative Preferred Securities (note C) Without Mandatory Redemption (notes D and E) \$100 par value series				
4.08% .....	250,000	103.00	\$ 25,000	\$ 25,000
4.18% .....	249,942	103.00	24,994	24,994
4.30% .....	250,000	102.75	25,000	25,000
5.05% .....	250,000	103.00	25,000	25,000
5.28% .....	250,000	103.00	25,000	25,000
6.80% .....	250,000	102.00	25,000	25,000
6.92% .....	600,000	—	60,000	60,000
7.40% .....	500,000	101.00	50,000	50,000
7.52% .....	500,000	101.00	50,000	50,000
7.70% (note E) .....	—	—	—	60,000
\$25 par value series				
6.75% .....	600,000	—	\$ 15,000	\$ 15,000
Total Preferred Stock without Mandatory Redemption .....			<u>\$ 324,994</u>	<u>\$ 384,994</u>
With Mandatory Redemption (notes D and F) \$100 par value series				
7.44% .....	750,000	—	\$ 75,000	\$ 75,000
5.97% .....	750,000	—	75,000	75,000
Total Preferred Stock with Mandatory Redemption (note G) .....			<u>\$ 150,000</u>	<u>\$ 150,000</u>
Monthly Income Preferred Securities (notes D, F, G and H)				
9.375% .....	6,000,000	—	\$ 150,000	\$ 150,000
8.00% .....	2,400,000	—	\$ 60,000	—
Total Monthly Income Preferred Securities .....			<u>\$ 210,000</u>	<u>\$ 150,000</u>

- (A) Total authorized and unissued shares include 7,302,488 shares of Enterprise Common Stock reserved for issuance through Enterprise's Dividend Reinvestment and Stock Purchase Plan and various employee benefit plans. In 1995, no shares of Enterprise Common Stock were issued or sold and in 1994, 1,009,674 shares were issued and sold for \$28,495,122.
- (B) Enterprise has authorized a class of 50,000,000 shares of Preferred Stock without par value, none of which is outstanding.
- (C) As of December 31, 1995, there were 2,900,058 shares of \$100 par value and 9,400,000 shares of \$25 par value Cumulative Preferred Stock which were authorized and unissued, and which upon issuance may or may not provide for mandatory sinking fund redemption. If dividends upon any shares of Preferred Stock are in arrears in an amount equal to the annual dividend thereon, voting rights for the election of a majority of PSE&G's Board of Directors become operative and continue until all accumulated and unpaid dividends thereon have been paid, whereupon all such voting rights cease, subject to being again revived from time to time.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

- (D) At December 31, 1995, the annual dividend requirement and embedded dividend for Preferred Stock without mandatory redemption were \$20,046,765 and 6.14%, respectively, and for Preferred Stock with mandatory redemption were \$10,057,500 and 6.75%, respectively.
- At December 31, 1994, the annual dividend requirement and embedded dividend for Preferred Stock without mandatory redemption were \$24,666,763 and 6.39%, respectively and for Preferred Stock with mandatory redemption were \$10,057,500 and 6.75%, respectively.
- At December 31, 1995, the annualized monthly income requirement of the Monthly Income Preferred Securities and their embedded cost were \$18,862,500 and 6.04%, respectively.
- At December 31, 1994, the annualized monthly income requirement of the Monthly Income Preferred Securities and their embedded cost were \$14,062,500 and 6.31%, respectively.
- (E) On October 16, 1995, PSE&G redeemed all of the 600,000 shares of its outstanding 7.70% Cumulative Preferred Stock (\$100 par), at a redemption price of \$100.79.
- (F) For information concerning fair value of financial instruments, see Note 8—Financial Instruments and Risk Management.
- (G) On September 12, 1995, Partnership issued 2,400,000 shares of its 8% Monthly Income Preferred Securities, Series B, with a stated liquidation preference of \$25 each.
- (H) Public Service Electric and Gas Capital, L.P. (Partnership) was formed for the purpose of issuing Monthly Income Preferred Securities. The proceeds of Monthly Income Preferred Securities sales are lent to PSE&G and evidenced by PSE&G's Deferrable Interest Subordinated Debentures. If and for as long as payments on PSE&G's Deferred Interest Subordinated Debentures have been deferred, or PSE&G has defaulted on the indenture related thereto or its guarantee thereof, PSE&G may not pay any dividends on its Capital Stock.

### Note 5. Deferred Items

#### Property Abandonments

The BPU has authorized PSE&G to recover after-tax property abandonment costs from its customers. The following table reflects the application of Statement of Financial Accounting Standards No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs," as amended (SFAS 90), on property abandonments, and related tax effects, for which no return is earned. The net-of-tax discount rate used was between 4.443% and 7.801%. (See Note 2—Rate Matters). The following table reflects property abandonments:

	Property Abandonments			
	December 31, 1995		December 31, 1994	
	Discounted Cost	Taxes	Discounted Cost	Taxes
	(Thousands of Dollars)			
Atlantic Project .....	\$58,221	\$24,440	\$70,130	\$29,453
LNG Project .....	2,992	957	7,287	2,635
Uranium Projects .....	8,907	3,871	10,852	4,677
	<u>\$70,120</u>	<u>\$29,268</u>	<u>\$88,269</u>	<u>\$36,765'</u>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### Under (Over) Recovered Electric Energy and Gas Costs—net

Recoveries of electric energy and gas costs are determined by the BPU under the LEAC and LGAC. PSE&G's deferred fuel balances as of December 31, 1995 and December 31, 1994, reflect underrecovered costs as follows:

	December 31,	
	1995	1994
	(Millions)	
Underrecovered Electric Energy Costs .....	\$162.4	\$172.0
Underrecovered Gas Fuel Costs .....	8.2	.6
Total .....	<u>\$170.6</u>	<u>\$172.6</u>

### Unrecovered Plant and Regulatory Study Costs

Amounts shown in the consolidated balance sheets consist of costs associated with developing, consolidating and documenting the specific design basis of PSE&G's jointly owned nuclear generating stations, as well as PSE&G's share of costs associated with the cancellation of the Hydrogen Water Chemistry System Project (HWCS Project) at Peach Bottom. PSE&G has received both BPU and FERC approval to defer and amortize, over the remaining life of the Salem and Hope Creek nuclear units, costs associated with configuration baseline documentation and the canceled HWCS Project. PSE&G has received FERC approval to defer and amortize over the remaining life of the applicable Peach Bottom units, costs associated with the configuration baseline documentation and the canceled HWCS Project. In accordance with the filed Alternative Rate Plan, PSE&G has requested to have separate mechanisms to ensure continued recovery of costs associated with activities mandated or approved by state or federal agencies or otherwise out of PSE&G's control. (See Note 2—Rate Matters).

### Unamortized Debt Expense

Gains and losses and the costs of issuing and redeeming long-term debt for PSE&G are deferred and amortized over the life of the applicable debt.

### Oil and Gas Property Write-Down

On December 31, 1992, the BPU approved the recovery of PSE&G's deferral of an EDC write-down through PSE&G's LGAC over a ten-year period beginning January 1, 1993. At December 31, 1995 and 1994, the remaining balance to be amortized was \$36.1 million and \$41.2, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 6. Schedule of Consolidated Debt

Interest Rates	Due	December 31,	
		1995	1994
		(Thousands of Dollars)	
<b>Long-Term</b>			
<b>PSE&amp;G</b>			
<b>First and Refunding Mortgage Bonds (note A)</b>			
4¾%—6%	1995	\$ —	\$ 310,000
6⅞%—7⅞%	1997	300,000	300,000
6%	1998	100,000	100,000
8¾%	1999	100,000	100,000
6%—7⅝%	2000	400,000	400,000
6⅞%—9⅞%	2001-2005	1,125,000	1,125,000
6.30%—6.90%	2006-2010	177,990	234,310
6.80%—7⅜%	2011-2015	198,500	198,500
Variable	2011-2015	42,620	—
6.45%—8.10%	2016-2020	29,600	29,600
Variable	2016-2020	13,700	—
5.20%—9¼%	2021-2025	1,263,500	1,267,500
5.70%—6.55%	2026-2030	244,835	244,835
5.45%—6.40%	2031-2035	399,565	399,565
5%—8%	2037	15,001	15,001
<b>Medium-Term Notes</b>			
7.10%—7.13%	1997	100,000	—
7.15%—7.18%	2023	40,500	40,500
8.10%—8.16%	2009	60,000	60,000
Total First and Refunding Mortgage Bonds		\$4,610,811	\$4,824,811
<b>Debenture Bonds Unsecured</b>			
6%	1998	\$ 18,195	\$ 18,195
Total Debenture Bonds		18,195	18,195
Principal Amount Outstanding (note F)		4,629,006	4,843,006
Amounts Due Within One Year (note B)		—	(310,200)
Net Unamortized Discount		(42,738)	(46,019)
Total Long-Term Debt of PSE&G (note G)		4,586,268	4,486,787
<b>EDHI</b>			
<b>Capital (note C) Senior notes</b>			
9.875%—10.05%	1998	122,500	165,000
<b>Medium-Term Notes</b>			
5.65%—9.55%	1995	—	112,000
9.00%	1996	20,000	20,000
5.79%—5.92%	1997	27,000	27,000
9.00%	1998	75,000	75,000
8.95%—9.93%	1999	155,000	155,000
6.54%	2000	78,000	78,000
Principal Amount Outstanding (note F)		477,500	632,000
Amounts Due Within One Year (note B)		(62,482)	(154,405)
Net Unamortized Discount		(901)	(1,278)
Total Long-Term Debt of Capital		414,117	476,317

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

		December 31,	
<u>Interest Rates</u>	<u>Due</u>	<u>1995</u>	<u>1994</u>
		(Thousands of Dollars)	
Funding (note D)			
9.54%	1995 .....	—	35,000
9.55%	1996 .....	28,000	28,000
6.85%—9.59%	1997 .....	55,000	55,000
9.95%	1998 .....	83,000	83,000
7.58%	1999 .....	45,000	45,000
Principal Amount Outstanding (note F) .....		211,000	246,000
Amounts Due Within One Year (note B) .....		(28,000)	(35,000)
Total Long-Term Debt of Funding .....		183,000	211,000
EGDC Mortgage Notes			
10.625%—12.75%	2012 (note F) .....	6,554	6,686
Amounts Due Within One Year (note B) .....		(148)	(133)
Total Long-Term Debt of EGDC .....		6,406	6,553
Total Long-Term Debt of EDHI .....		603,523	693,870
Consolidated Long-Term Debt (note E) .....		\$5,189,791	\$5,180,657

**Notes:**

- (A) PSE&G's Mortgage, securing the Bonds, constitutes a direct first mortgage lien on substantially all PSE&G's property and franchises.
- (B) The aggregate principal amounts of mandatory requirements for sinking funds and maturities for each of the five years following December 31, 1995 are as follows:

Year	Sinking Funds	Maturities				
	Capital	PSE&G	Capital	EGDC	Funding	Total
(Thousands of Dollars)						
1996	\$ 42,500	\$ —	\$ 20,000	\$148	\$ 28,000	\$ 90,648
1997	42,500	400,000	27,000	166	55,000	524,666
1998	37,500	118,195	75,000	184	83,000	313,879
1999	—	100,000	155,000	205	45,000	300,205
2000	—	400,000	78,000	228	—	478,228
	<u>\$122,500</u>	<u>\$1,018,195</u>	<u>\$355,000</u>	<u>\$931</u>	<u>\$211,000</u>	<u>\$1,707,626</u>

In January 1996 principal amounts of \$3.5 million of the 8¾% EE First and Refunding Mortgage Bonds Series and \$16.942 million of the 8¾% Series HH First and Refunding Mortgage Bonds were reacquired.

On February 1, 1996 a sinking fund in the principal amount of \$1.5 million of the 8¾% Series HH First and Refunding Mortgage Bonds was met. In addition, the remaining principal amounts of \$192.5 million of the 8¾% Series EE and \$130.058 million of the 8¾% Series HH were defeased.

- (C) Capital has provided up to \$750 million debt financing for EDHI's businesses on the basis of a net worth maintenance agreement with Enterprise. Since January 31, 1995, Capital has agreed to limit its borrowings to no more than \$650 million.
- (D) Funding provides debt financing for EDHI's businesses other than EGDC on the basis of unconditional guarantees from EDHI.
- (E) At December 31, 1995 and 1994, the annual interest requirement on long-term debt was \$399.8 million and \$422.7 million, of which \$315.6 million and \$335.6 million was the requirement for Bonds. The embedded interest cost on long-term debt on such date was 7.71% and 7.79%, respectively.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

(F) For information concerning fair value of financial instruments, see Note 8—Financial Instruments and Risk Management.

(G) At December 31, 1995 and 1994, PSE&G's annual interest requirement on long-term debt was \$330.5 million and \$343.3 million, of which \$315.6 million and \$335.6 million, respectively, was the requirement for Bonds. The embedded interest cost on long-term debt was 7.54% and 7.59%, respectively.

PSE&G has authorization from the BPU to issue approximately \$4.375 billion aggregate amount of additional bonds/MTNs/Preferred Stock/Monthly Income Preferred Securities through 1997 for refunding purposes.

### SHORT-TERM (Commercial Paper and Loans)

Commercial paper represents unsecured bearer promissory notes sold through dealers at a discount with a term of nine months or less.

Bank loans represent PSE&G's unsecured promissory notes issued under informal credit arrangements with various banks and have a term of eleven months or less.

### PSE&G

	<u>1995</u>	<u>1994</u>	<u>1993</u>
	(Millions of Dollars)		
Principal amount outstanding at end of year, primarily commercial paper .....	\$567	\$402	\$533
Weighted average interest rate for Short-Term Debt at year-end .....	5.93%	6.07%	3.34%

PSE&G has authorization from the BPU to issue and have outstanding not more than \$1 billion of its short-term obligations at any one time, consisting of commercial paper and other unsecured borrowings from banks and other lenders. This authorization expires January 1, 1997.

PSE&G has a \$500 million one year revolving credit agreement expiring in August 1996 and a \$500 million five year revolving credit agreement expiring in August 2000 with a group of commercial banks each of which provides for borrowing up to one year. As of December 31, 1995, there was no short-term debt outstanding under this agreement.

PSE&G has a \$50 million uncommitted Line of Credit facility extended by a bank to primarily support short-term borrowings all of which was outstanding under this facility on December 31, 1995 and is included in the table above.

PSE&G had various Lines of Credit facility extended by a bank to primarily support the issuance of Letters of Credit. As of December 31, 1995, Letters of Credit were issued in the amount of \$20.6 million.

Fuelco has a \$150 million commercial paper program to finance a 42.49% share of Peach Bottom nuclear fuel, supported by a \$150 million revolving credit facility with a group of banks, which expires in June 1996. PSE&G has guaranteed repayment of Fuelco's respective obligations. As of December 31, 1995, 1994 and 1993, Fuelco had commercial paper of \$87.7 million, \$93.7 million and \$108.7 million, respectively, outstanding under such program, which amounts are included in the table above.

PSCRC has a \$30 million revolving credit facility supported by a PSE&G subscription agreement in an aggregate amount of \$30 million which terminates on March 7, 1996. PSCRC is presently in the process of negotiating a one year extension for this facility. As of December 31, 1995, PSCRC had \$30 million outstanding under this facility, which amount is included in the table above.

PSE&G has entered into standby financing arrangements with a bank totaling \$61 million. These facilities support tax-exempt multi-mode financings done through the New Jersey Economic Development Authority and

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

the York County (Pennsylvania) Industrial Development Authority. As of December 31, 1995, no amounts were outstanding under such arrangements.

### EDHI

	1995	1994	1993
	(Millions of Dollars)		
Principal amount outstanding at end of year .....	\$182	\$ 90	\$ 45
Weighted average interest rate for Short-Term Debt at year-end .....	6.26%	5.97%	3.47%

At December 31, 1995, Funding had a \$225 million commercial paper program supported by a direct pay commercial bank letter of credit and revolving credit facility and a \$225 million revolving credit facility, each of which expires in March 1998. At December 31, 1995, there was \$100 million outstanding under this agreement.

### ENTERPRISE

At December 31, 1995, 1994 and 1993, Enterprise had a \$25 million line of credit with a bank. At December 31, 1995, 1994 and 1993, Enterprise had no borrowings under this line.

### Note 7. Long-Term Investments

Long-Term Investments are primarily those of EDHI. A summary of Long-Term Investments is as follows:

	1995	1994
	(Millions of Dollars)	
Lease Agreements (see Note 11—Leasing Activities):		
Leveraged Leases .....	\$ 845	\$ 789
Direct-Financing Leases .....	35	76
Other Leases .....	6	6
Total .....	<u>886</u>	<u>871</u>
Partnerships:		
General Partnerships .....	177	168
Limited Partnerships .....	522	437
Total .....	<u>699</u>	<u>605</u>
Corporate Joint Ventures .....	49	26
Securities .....	76	75
Valuation Allowances .....	(21)	(17)
Other Investments .....	133	66
Total Long-Term Investments .....	<u>\$1,822</u>	<u>\$1,626</u>

PSRC's leveraged leases are reported net of principal and interest on nonrecourse loans, unearned income and deferred tax credits. Income and deferred tax credits are recognized at a level rate of return from each lease during the periods in which the net investment is positive.

Partnership investments are those of PSRC, EGDC and CEA and are undertaken with other investors. PSRC is a limited partner in various partnerships and is committed to make investments from time to time upon the request of the respective general partners. As of December 31, 1995, \$58 million remained as PSRC's unfunded commitment subject to call.

PSRC has invested in securities and limited partnerships investing in securities, which are recorded at fair value. Realized investment gains and losses on the sale of investment securities are determined utilizing the specific cost identification method. (See Note 8—Financial Instruments and Risk Management.)

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

As of December 31, 1995 and 1994, EDHI's long-term investments aggregated \$1.7 billion and \$1.6 billion, respectively, and its property, plant and equipment (net of accumulated depreciation and amortization and valuation allowances) aggregated \$.7 billion. As of December 31, 1995 and December 31, 1994, EDHI comprised 15% of Enterprise's assets.

### Note 8. Financial Instruments and Risk Management

Enterprise's operations give rise to exposure to market risks from changes in crude oil and natural gas prices, interest rates, foreign exchange rates and security prices of investments. Enterprise's policy is to use derivatives for the purpose of managing market risk consistent with its business plans and prudent practices. Enterprise does not hold or issue financial instruments for trading purposes.

The notional amounts of derivatives summarized below do not represent amounts exchanged by the parties and, thus, are not a measure of the exposure of Enterprise through its use of derivatives. The amounts exchanged, under the terms of the derivatives, are calculated on the basis of the notional amounts. Enterprise limits its exposure to credit-related losses in the event of nonperformance by counterparties by limiting its counterparties to those with high credit ratings.

#### Natural Gas and Crude Oil Hedging

EDC sold natural gas futures contracts outstanding at December 31, 1995 and 1994 which hedged 21,250,000 mmbtu and 10,650,000 mmbtu, respectively. Such amounts represented approximately 26% and 13% of EDC's anticipated domestic natural gas production in 1996 and 1995, respectively, at average sales prices of \$1.93 per mmbtu and \$1.95 per mmbtu, respectively.

At December 31, 1995, EDC sold crude oil futures contracts outstanding which hedged 1.5 million barrels of oil representing approximately 38% of EDC's anticipated domestic oil production in 1996 at an average price of \$17.74 per barrel.

The deferred unrealized gains (losses) at December 31, 1995 and 1994 related to EDC's futures contracts were (\$5.1) million and \$2.6 million, respectively.

Through December 31, 1995 and 1994, USEP entered into swaps for future contracts to buy 4,970,000 mmbtu and 2,850,000 mmbtu of natural gas related to fixed-price sales commitments. Such swaps hedged approximately 54% and 73% of sales commitments at December 31, 1995 and 1994 at average prices of \$1.78 and \$1.94 per mmbtu, respectively. USEP had deferred unrealized gains of \$3.1 million at December 31, 1995 and unrealized losses of \$.7 million at December 31, 1994.

#### Interest Rate Swap

Capital entered into an interest rate swap in December, 1990 to allow EDHI to borrow at floating rates and effectively swap them into fixed rates. The interest differential to be received or paid under the interest rate swap agreement is accrued over the life of the agreement as an adjustment to the interest expense of the related borrowing. The swap expired on December 11, 1995.

	1995	1994
	(Thousands of Dollars)	
Pay-fixed swap		
Notional amount .....	\$100,000	\$100,000
Pay rate .....	8.0%	8.0%
Average receive rate .....	6.4%	4.1%
Year-end receive rate .....	— %	6.8%

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### Foreign Exchange

During 1994, PSRC entered into a forward purchase contract for foreign currency to hedge an EDC firm purchase commitment denominated in pound sterling. The EDC commitment related to the acquisition of Industrial Scotland Energy Limited (ISE) for approximately 21 million pounds. The realized gain of approximately \$800 thousand on the forward purchase contract for foreign currency was used to reduce the net acquisition cost allocated to ISE's assets upon completion of the acquisition in June 1994.

Currently, substantially all of Enterprise's foreign revenues and expenses are denominated in U.S. dollars.

### Security Swap

During 1994, PSRC entered into two agreements to swap portions of its ownership interest in certain equity securities, held in a partnership, to the S&P 500 return. The purpose of the swaps was to minimize PSRC's exposure to the potential price volatility of such equity securities. The agreements had respective notional amounts of \$17.6 million and \$12.9 million.

The aggregate notional amounts swapped and the year end unrealized gain during 1994 for these two agreements were \$30.5 million and \$3.8 million, respectively.

In March 1995, the equity securities, in which PSRC had an ownership interest, were exchanged for equity securities of another entity. Consequently, PSRC terminated the security swap and realized a pre-tax gain of \$3.5 million which was offset by the reversal of the \$3.8 million unrealized gain at year end 1994.

### Fair Value of Financial Instruments

The estimated fair value was determined using the market quotations or values of securities with similar terms, credit ratings, remaining maturities and redemptions at the end of 1995 and 1994, respectively.

	1995		1994	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars)			
Long-Term Debt:				
EDHI .....	\$ 603,523	\$ 730,000	\$ 884,686	\$ 930,000
PSE&G .....	4,629,006	4,828,008	4,843,006	4,500,000
Preferred Securities Subject to Mandatory Redemption:				
PSE&G Cumulative Preferred Securities .....	150,000	156,000	150,000	145,900
Monthly Income Preferred Securities .....	210,000	225,300	150,000	158,300

### Note 9. Cash and Cash Equivalents

The December 31, 1995 and 1994 balances consist primarily of working funds and highly liquid marketable securities (commercial paper) with a maturity of three months or less.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### Note 10. Federal Income Taxes

A reconciliation of reported Net Income with pretax income and of Federal income tax expense with the amount computed by multiplying pretax income by the statutory Federal income tax rate of 35% is as follows:

	1995	1994	1993
	(Thousands of Dollars)		
Net Income .....	\$ 662,323	\$ 679,033	\$600,933
Preferred securities dividend requirements .....	34,236	40,467	38,114
SFAS 109 Cumulative Effect .....	—	—	(5,414)
Subtotal .....	<u>696,559</u>	<u>719,500</u>	<u>633,633</u>
Federal income taxes:			
Operating income:			
Current provision .....	183,268	162,521	151,208
Provision for deferred income taxes—net(A) .....	192,648	173,327	186,256
Investment tax credits—net .....	(21,919)	(23,297)	(23,784)
Total included in operating income .....	353,997	312,551	313,680
Miscellaneous other income:			
Current provision .....	(9,897)	(8,186)	(14,340)
Provision for deferred income taxes(A) .....	9,816	10,422	9,815
SFAS 90 deferred income taxes(A) .....	2,161	2,530	2,948
Total Federal income tax provisions .....	<u>356,077</u>	<u>317,317</u>	<u>312,103</u>
Pretax income .....	<u>\$1,052,636</u>	<u>\$1,036,817</u>	<u>\$945,736</u>

Reconciliation between total Federal income tax provisions and tax computed at the statutory tax rate on pretax income:

	1995	1994	1993
	(Thousands of Dollars)		
Tax computed at the statutory rate .....	\$368,423	\$362,887	\$331,008
Increase (decrease) attributable to flow through of certain tax adjustments:			
Depreciation .....	16,257	(4,597)	3,347
Amortization of investment tax credits .....	(21,919)	(23,297)	(23,784)
Other .....	(6,684)	(17,676)	1,532
Subtotal .....	<u>(12,346)</u>	<u>(45,570)</u>	<u>(18,905)</u>
Total Federal income tax provisions .....	<u>\$356,077</u>	<u>\$317,317</u>	<u>\$312,103</u>
Effective Federal income tax rate .....	33.8%	30.6%	33.0%

(A) The provision for deferred income taxes represents the tax effects of the following items:

	1995	1994	1993
	(Thousands of Dollars)		
Deferred Credits:			
Additional tax depreciation and amortization .....	\$174,190	\$109,106	\$112,814
Leasing Activities .....	64,567	60,129	34,958
Property Abandonments .....	(7,411)	(6,606)	(6,632)
Oil and Gas Property Write-Down .....	(2,451)	(2,451)	(2,451)
Deferred fuel costs—net .....	(3,601)	39,361	63,330
Other .....	(20,669)	(13,260)	(3,000)
Total .....	<u>\$204,625</u>	<u>\$186,279</u>	<u>\$199,019</u>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Between the years 1987 and 1994, Enterprise's Federal alternative minimum tax (AMT) liability exceeded its regular Federal income tax liability. This excess can be carried forward indefinitely to offset regular income tax liability in future years. Enterprise commenced using these AMT credits in 1995 and expects to continue using them in future years as regular tax liability exceeds AMT. As of December 31, 1995, 1994 and 1993, Enterprise had AMT credits of \$203 million, \$256 million and \$247 million, respectively.

Since 1986, Enterprise has filed a consolidated Federal income tax return on behalf of itself and its subsidiaries. Prior to 1986, PSE&G filed consolidated tax returns. In March, 1992, the Internal Revenue Service (IRS) issued a Revenue Agent's Report (RAR) following completion of examination of PSE&G's consolidated tax return for 1985 and Enterprise's consolidated tax returns for 1986 and 1987, proposing various adjustments for such years which would increase Enterprise's consolidated Federal income tax liability by approximately \$121 million, exclusive of interest and penalties, of which approximately \$118 million is attributable to PSE&G. Interest after taxes on these proposed adjustments is currently estimated to be approximately \$119 million as of December 31, 1995 and will continue to accrue at the Federal rate for large corporate underpayments, currently 11% annually.

The most significant of these proposed adjustments relates to the IRS contention that PSE&G's Hope Creek nuclear unit is a partnership with a short 1986 taxable year. In addition, the IRS contends that the tax in-service date of that unit is four months later than the date claimed by PSE&G. In June 1992, Enterprise and PSE&G filed a protest with the IRS disagreeing with certain of the proposed adjustments (including those related to Hope Creek) contained in the RAR for taxable years 1985 through 1987 and continue to contest these issues. Any tax adjustments resulting from the RAR would reduce Enterprise's and PSE&G's respective deferred credits for accumulated deferred income taxes. While PSE&G believes that assessments attributable to it are generally recoverable from its customers in rates, no assurances can be given as to what regulatory treatment may be afforded by the BPU.

On January 1, 1993, Enterprise adopted SFAS 109 without restating prior years' financial statements which resulted in Enterprise recording a \$5.4 million cumulative effect increase in its net income. Under SFAS 109, deferred taxes are provided at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Since management believes that it is probable that the effects of SFAS 109 on PSE&G, principally the accumulated tax benefits that previously have been treated as a flow-through item to customers, will be recovered from utility customers in the future, an offsetting regulatory asset was established. As of December 31, 1995, PSE&G had recorded a deferred tax liability and an offsetting regulatory asset of \$769 million representing the future revenue expected to be recovered through rates based upon established regulatory practices which permit recovery of current taxes payable. This amount was determined using the 1995 Federal income tax rate of 35%.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### SFAS 109

The following is an analysis of accumulated deferred income taxes:

<u>ACCUMULATED DEFERRED INCOME TAXES</u>	<u>1995</u>	<u>1994</u>
	(Thousands of Dollars)	
<b>Assets:</b>		
Current (net) .....	\$ 27,571	\$ 25,311
Non-Current:		
Unrecovered Investment Tax Credits .....	129,713	136,402
Nuclear Decommissioning .....	25,241	25,082
Hope Creek Cost Disallowance .....	—	10,127
Construction Period Interest and Taxes .....	17,199	15,913
Vacation Pay .....	6,681	6,822
AMT Credit .....	202,655	255,828
Real Estate Impairment .....	5,213	20,932
Other .....	4,107	6,863
Total Non-Current .....	<u>\$ 390,809</u>	<u>\$ 477,969</u>
Total Assets .....	<u>\$ 418,380</u>	<u>\$ 503,280</u>
<b>Liabilities:</b>		
Non-Current:		
Plant Related Items .....	\$2,370,830	\$2,268,688
Leasing Activities .....	616,914	580,415
Property Abandonments .....	21,469	26,971
Oil and Gas Property Write-Down .....	13,061	14,925
Deferred Electric Energy & Gas Costs .....	56,283	59,884
Unamortized Debt Expense .....	36,945	37,599
Taxes Recoverable Through Future Rates (net) .....	262,625	270,684
Other .....	107,302	124,193
Total Non-Current .....	<u>\$3,485,429</u>	<u>\$3,383,359</u>
Total Liabilities .....	<u>\$3,485,429</u>	<u>\$3,383,359</u>
<b>Summary—Accumulated Deferred Income Taxes</b>		
Net Current Assets .....	\$ 27,571	\$ 25,311
Net Deferred Liability .....	\$3,094,620	\$2,905,390
Total .....	<u>\$3,067,049</u>	<u>\$2,880,079</u>

### Note 11. Leasing Activities

#### As Lessee

The Consolidated Balance Sheets include assets and related obligations applicable to capital leases under which PSE&G is a lessee. The total amortization of the leased assets and interest on the lease obligations equals the net minimum lease payments included in rent expense for capital leases.

Capital leases of PSE&G relate primarily to its corporate headquarters and other capital equipment. Certain of the leases contain renewal and purchase options and also contain escalation clauses.

Enterprise and its other subsidiaries are not lessees in any capitalized leases.

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

Utility plant includes the following amounts for capital leases at December 31:

	<u>1995</u>	<u>1994</u>
	<u>(Thousands of Dollars)</u>	
Common Plant .....	\$58,610	\$58,610
Less: Accumulated Amortization .....	<u>5,499</u>	<u>4,840</u>
Net Assets under Capital Leases .....	<u>\$53,111</u>	<u>\$53,770</u>

Future minimum lease payments for noncancelable capital and operating leases at December 31, 1995 were:

	<u>Capital Leases</u>	<u>Operating Leases</u>
	<u>(Thousands of Dollars)</u>	
1996 .....	13,174	14,616
1997 .....	13,175	12,580
1998 .....	13,176	8,638
1999 .....	13,177	6,517
2000 .....	12,834	4,449
Later Years .....	<u>189,229</u>	<u>12,998</u>
Minimum Lease Payments .....	254,765	<u>\$59,798</u>
Less: Amount representing estimated executory costs, together with any profit thereon, included in minimum lease payments .....	<u>126,029</u>	
Net minimum lease payments .....	128,736	
Less: Amount representing interest .....	<u>75,625</u>	
Present value of net minimum lease payments(A) .....	<u>\$53,111</u>	

- (A) Reflected in the Consolidated Balance Sheets for 1995 and 1994 were Capital Lease Obligations of \$53.111 million and \$53.770 million which includes Capital Lease Obligations due within one year of \$739 thousand and \$659 thousand, respectively.

The following schedule shows the composition of rent expense included in Operating Expenses:

	<u>For the Years Ended December 31,</u>		
	<u>1995</u>	<u>1994</u>	<u>1993</u>
	<u>(Thousands of Dollars)</u>		
Interest on Capital Lease Obligations .....	\$ 6,084	\$ 6,156	\$ 6,074
Amortization of Utility Plant under Capital Leases .....	<u>659</u>	<u>588</u>	<u>513</u>
Net minimum lease payments relating to Capital Leases .....	6,743	6,744	6,587
Other Lease payments .....	<u>27,219</u>	<u>28,447</u>	<u>22,132</u>
Total Rent Expense .....	<u>\$33,962</u>	<u>\$35,191</u>	<u>\$28,719</u>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### As Lessor

PSRC's net investments in leveraged and direct financing leases are composed of the following elements:

	December 31, 1995			December 31, 1994		
	(Millions of Dollars)					
	Leveraged Leases	Direct Financing Leases	Total	Leveraged Leases	Direct Financing Leases	Total
Lease rents receivable .....	\$1,031	\$39	\$1,070	\$ 990	\$92	\$1,082
Estimated residual value .....	635	8	643	622	13	635
	1,666	47	1,713	1,612	105	1,717
Unearned and deferred income ...	(821)	(12)	(833)	(823)	(29)	(852)
Total investments .....	845	35	880	789	76	865
Deferred taxes .....	(405)	(11)	(416)	(333)	(20)	(353)
Net investments .....	<u>\$ 440</u>	<u>\$24</u>	<u>\$ 464</u>	<u>\$ 456</u>	<u>\$56</u>	<u>\$ 512</u>

PSRC's other capital leases are with various regional, state and city authorities for transportation equipment and aggregated \$6 million as of December 31, 1995 and 1994.

During 1995, PSRC converted two Airbus A-300 aircraft under direct-finance leases to operating leases. As of December 31, 1995, such aircraft had a net asset value of \$11 million. On January 31, 1996, the aircraft were sold for an amount approximating their net asset value.

### Note 12. Commitments and Contingent Liabilities

#### Nuclear Performance Standard

The BPU has established its NPS for nuclear generating stations owned by New Jersey electric utilities, including the five nuclear units in which PSE&G has an ownership interest: Salem Units 1 and 2—42.59%; Hope Creek—95%; and Peach Bottom Units 2 and 3—42.49%. PSE&G operates Salem and Hope Creek, while Peach Bottom is operated by PECO Energy, Inc. (PECO).

The penalty/reward under the NPS is a percentage of replacement power costs. (See table below.)

Capacity Factor Range	Reward	Penalty
Equal to or greater than 75% .....	30%	—
Equal to or greater than 65% and less than 75% .....	None	None
Equal to or greater than 55% and less than 65% .....	—	30%
Equal to or greater than 45% and less than 55% .....	—	40%
Equal to or greater than 40% and less than 45% .....	—	50%
Below 40% .....	BPU Intervenes	

Under the NPS, the capacity factor is calculated annually using maximum dependable capability of the five nuclear units in which PSE&G owns an interest. This method takes into account actual operating conditions of the units.

While the NPS does not specifically have a gross negligence provision, the BPU has indicated that it would consider allegations of gross negligence brought upon a sufficient factual basis. A finding of gross negligence could result in penalties other than those prescribed under the NPS. During 1995, the five nuclear units in which PSE&G has an ownership interest aggregated a 62% combined capacity factor which resulted in a penalty for

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

1995 of approximately \$3.5 million. On January 16, 1996, PSE&G filed its Alternative Rate Plan with the BPU which proposes the elimination of the NPS. See Note 2.

Based upon current projections and assumptions regarding PSE&G's five nuclear units during 1996, including the return of Hope Creek to service in early March, the return of Salem 2 in the third quarter and the continued outage of Salem 1 for the remainder of the year, the 1996 aggregate capacity factor would be approximately 57%, which would result in a penalty ranging from \$11 to \$12 million. Both of the Salem units are currently out of service and their return dates are subject to completion of testing, analysis, repair activity and NRC concurrence that they are prepared to restart. Restart of Salem 1, which had originally been scheduled for the second quarter of 1996, will be delayed for a substantial period as a result of the ongoing steam generator inspection and analysis. Salem 2, which is also undergoing steam generator inspection and analysis is still scheduled to return to service in the third quarter of 1996. The inability to successfully return these units to continuous, safe operation could have a material effect on the financial position, results of operation and net cash flows of Enterprise and PSE&G.

Certain of the owners of Salem have indicated that they may seek to hold PSE&G responsible for their share of costs of the current outage. PSE&G cannot predict what actions, if any, may be taken.

### Nuclear Insurance Coverages and Assessments

PSE&G's insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

<u>Type and Source of Coverages</u>	<u>Total Site Coverages</u>	<u>PSE&amp;G Maximum Assessments for a Single Incident</u>
	(Millions of Dollars)	
Public Liability:		
American Nuclear Insurers .....	\$ 200.0	\$ —
Indemnity(A) .....	8,720.3	210.2
	<u>\$8,920.3(B)</u>	<u>\$210.2</u>
Nuclear Worker Liability:		
American Nuclear Insurers(C) .....	\$ 200.0	\$ 8.1
Property Damage:		
Nuclear Mutual Limited .....	\$ 500.0	\$ 9.2
Nuclear Electric Insurance Ltd. (NEIL II) .....	1,400.0	8.3(D)
Nuclear Electric Insurance Ltd. (NEIL III) .....	850.0	9.2
	<u>\$2,750.0</u>	<u>\$ 26.7</u>
Replacement Power:		
Nuclear Electric Insurance Ltd (NEIL I) .....	\$ 3.5(E)	\$ 11.4

(A) Retrospective premium program under the Price-Anderson liability provisions of the Atomic Energy Act of 1954, as amended (Price-Anderson). Subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States. Assessment adjusted for inflation effective August 20, 1993.

(B) Limit of liability for each nuclear incident under Price-Anderson.

(C) Industry aggregate limit representing the potential liability from workers claiming exposure to the hazard of nuclear radiation. This policy includes automatic reinstatements up to an aggregate of \$200 million, thereby

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

providing total coverage of \$400 million. This policy does not increase PSE&G's obligation under Price-Anderson.

- (D) In the event of a second industry loss triggering NEIL II—coverage, the maximum retrospective premium assessment can increase to \$18.5 million.
- (E) Represents limit of coverage available to co-owners of Salem and Hope Creek, for each plant. Each co-owner purchases its own policy. PSE&G is currently covered for its percent ownership interest of this limit for each plant.

Price-Anderson sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the nation. The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current "limit of liability" is \$8.9 billion. All utilities owning a nuclear reactor, including PSE&G, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by Price-Anderson. Under Price-Anderson, each party with an ownership interest in a nuclear reactor can be assessed its share of \$79.3 million per reactor per incident, payable at \$10 million per reactor per incident per year. If the damages exceed the "limit of liability", the President is to submit to Congress a plan for providing additional compensation to the injured parties. Congress could impose further revenue raising measures on the nuclear industry to pay claims. PSE&G's maximum aggregate assessment per incident is \$210.2 million (based on PSE&G's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is \$26.5 million.

Further, a recent decision by the U.S. Court of Appeals for the Third Circuit, not involving PSE&G, held that the Price Anderson Act did not preclude awards based on state law claims for punitive damage.

PSE&G is a member of two industry mutual insurance companies; Nuclear Mutual Limited (NML), and Nuclear Electric Insurance Limited (NEIL). NML provides the primary property insurance at Salem and Hope Creek. NEIL provides excess property insurance through its NEIL II and NEIL III policies and replacement power coverage through its NEIL I policy. Both companies may make retrospective premium assessments in case of adverse loss experience. PSE&G's maximum potential liabilities under these assessments are included in the table and notes above. Certain of the policies also provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on a site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down. All coverages at Salem and Hope Creek remain fully in effect.

### Construction and Fuel Supplies

PSE&G has substantial commitments as part of its ongoing construction program which include capital requirements for nuclear fuel. PSE&G's construction program is continuously reviewed and periodically revised as a result of changes in economic conditions, revised load forecasts, changes in the scheduled retirement dates of existing facilities, changes in business strategies, site changes, cost escalations under construction contracts, requirements of regulatory authorities and laws, the timing of and amount of electric and gas rate changes and the ability of PSE&G to raise necessary capital. Pursuant to an electric integrated resource plan (IRP), PSE&G periodically reevaluates its forecasts of future customers, load and peak growth, sources of electric generating capacity and demand side management (DSM) to meet such projected growth, including the need to construct new electric generating capacity. The IRP takes into account assumptions concerning future demands of customers, effectiveness of conservation and load management activities, the long-term condition of PSE&G's plants, capacity available from electric utilities and other suppliers and the amounts of co-generation and other non-utility capacity projected to be available.

Based on PSE&G's construction program, construction expenditures are expected to aggregate approximately \$2.8 billion, which includes \$428 million for nuclear fuel and \$84 million of Allowance for Funds

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

used During Construction (AFDC) during the years 1996 through 2000. The estimate of construction requirements is based on expected project completion dates and includes anticipated escalation due to inflation of approximately 3%, annually. Therefore, construction delays or higher inflation levels could cause significant increases in these amounts. PSE&G expects to generate internally the funds necessary to satisfy its construction expenditures over the next five years, assuming adequate and timely recovery of costs, as to which no assurances can be given. In addition, PSE&G does not presently anticipate any difficulties in obtaining sufficient sources of fuel for electric generation or adequate gas supplies during the years 1996 through 2000.

### **Hazardous Waste**

Certain Federal and State laws authorize the United States Environmental Protection Agency (EPA) and the New Jersey Department of Environmental Protection (NJDEP), among other agencies, to issue orders and bring enforcement actions to compel responsible parties to take investigative and remedial actions at any site that is determined to present an imminent and substantial danger to the public or the environment because of an actual or threatened release of one or more hazardous substances. Because of the nature of PSE&G's business, including the production of electricity, the distribution of gas and, formerly, the manufacture of gas, various by-products and substances are or were produced or handled which contain constituents classified as hazardous. PSE&G generally provides for the disposal or processing of such substances through licensed independent contractors. However, these statutory provisions impose joint and several responsibility without regard to fault on all responsible parties, including the generators of the hazardous substances, for certain investigative and remediation costs at sites where these substances were disposed of or processed. PSE&G has been notified with respect to a number of such sites and the remediation of these potentially hazardous sites is receiving greater attention from the government agencies involved. Generally, actions directed at funding such site investigations and remediation include all suspected or known responsible parties. PSE&G does not expect its expenditures for any such site to have a material effect on its financial position, results of operations or net cash flows.

### **PSE&G Manufactured Gas Plant Remediation Program**

In 1988, NJDEP notified PSE&G that it had identified the need for PSE&G, pursuant to a formal arrangement, to systematically investigate and, if necessary, resolve environmental concerns extant at PSE&G's former manufactured gas plant sites. To date, NJDEP and PSE&G have identified 38 former gas plant sites. PSE&G is currently working with NJDEP under a program to assess, investigate and, if necessary, remediate environmental concerns at these sites (Remediation Program). The Remediation Program is periodically reviewed and revised by PSE&G based on regulatory requirements, experience with the Remediation Program and available technologies. The cost of the Remediation Program cannot be reasonably estimated, but experience to date indicates that costs of at least \$20 million per year could be incurred over a period of more than 30 years and that the overall cost could be material to PSE&G's financial position, results of operations or net cash flows.

Costs incurred through December 31, 1995 for the Remediation Program amounted to \$64.6 million, net of certain insurance proceeds. In addition, at December 31, 1995, PSE&G's estimated liability for remediation costs through 1998 aggregated \$96.3 million.

In accordance with a Stipulation approved by the BPU in 1992, PSE&G is recovering through its LEAC over a six-year period \$32 million of its actual remediation costs to reflect costs incurred through September 30, 1992. As of December 31, 1995, PSE&G has recovered \$27.8 million of the \$32 million of such costs. PSE&G is expected to recover the balance of \$4.2 million in its currently filed LGAC period ending in 1996.

### **Note 13. Postretirement Benefits Other Than Pensions**

On January 1, 1993, Enterprise and PSE&G adopted SFAS 106 which requires that the expected cost of employees' postretirement health care and insurance benefits be charged to expense during the years in which

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

employees render service. PSE&G elected to amortize, over 20 years, its unfunded obligation of \$609.3 million at January 1, 1993. The following table discloses the significant components of the net periodic postretirement benefit obligation:

<u>Net Periodic Postretirement Benefit Obligation</u>	<u>December 31,</u>		
	<u>1995</u>	<u>1994</u>	<u>1993</u>
		(Millions)	
Service cost .....	\$ 8.5	\$ 11.1	\$ 11.7
Interest on accumulated postretirement obligation .....	48.2	45.4	44.4
Amortization of transition obligation .....	30.5	30.5	30.5
Amortization of Net (Gain)/Loss (a) .....	(3.8)	—	—
Deferral of current expense .....	(50.7)	(57.8)	(58.6)
Annual net expense .....	<u>\$ 32.7</u>	<u>\$ 29.2</u>	<u>\$ 28.0</u>

(a) Reflects change in Plan Assumptions.

The discount rate used in determining the PSE&G net periodic postretirement benefit cost was 8.50% and 7.25% for 1995 and 1994, respectively.

A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the aggregate of the service and interest cost components of net periodic postretirement health care cost by approximately \$2.6 million, or 5.6%, and increase the accumulated postretirement benefit obligation as of December 31, 1995 by \$34.8 million, or 5.9%.

The assumed health care cost trend rates used in measuring the accumulated postretirement benefit obligation in 1995 were: medical costs for pre-age sixty-five retirees—13.0%, medical costs for post-age sixty-five retirees—9.0% and dental costs—7.0%; such rates are assumed to gradually decline to 5.0%, 5.0% and 5.0%, respectively, in 2011. The medical costs above include a provision for prescription drugs.

In its 1992 base rate case, PSE&G requested full recovery of the costs associated with postretirement benefits other than pensions (OPEB) on an accrual basis, in accordance with SFAS 106. The BPU's December 31, 1992 base rate order provided that (1) PSE&G's pay-as-you-go basis OPEB costs will continue to be included in cost of service and will be recoverable in base rates on a pay-as-you-go basis; (2) prudently incurred OPEB costs, that are accounted for on an accrual basis in accordance with SFAS 106, will be recoverable in future rates; (3) PSE&G should account for the differences between its OPEB costs on an accrual basis and the pay-as-you-go basis being recovered in rates as a regulatory asset; and (4) the issue of cash versus accrual accounting will be revisited and in the event that FASB or the SEC requires the use of accrual accounting for OPEB costs for rate-making purposes, the regulatory asset will be recoverable, through rates, over an appropriate amortization period.

Accordingly, PSE&G is accounting for the differences between its SFAS 106 accrual cost and the cash cost currently recovered through rates as a regulatory asset. OPEB costs charged to expenses during 1995 were \$32.6 million and accrued OPEB costs deferred were \$50.7 million. The amount of the unfunded liability, at December 31, 1995, as shown below, is \$717.9 million and funding options are currently being explored. The primary effect of adopting SFAS 106 on Enterprise's and PSE&G's financial reporting is on the presentation of their financial positions with minimal effect on their results of operations.

During January 1993 and subsequent to the receipt of the Order, the FASB's Emerging Issues Task Force (EITF) concluded that deferral of such costs is acceptable, provided regulators allow SFAS 106 costs in rates within approximately five years of the adoption of SFAS 106 for financial reporting purposes, with any cost deferrals recovered in approximately twenty years. In accordance with the Alternative Rate Plan filed, PSE&G

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

expects full SFAS 106 recovery in accordance with the EITF's view of such standard and believes that it is probable that any deferred costs will be recovered from utility customers within such twenty-year time period. As of December 31, 1995, PSE&G has deferred \$167.2 million of such costs. However, if recovery of SFAS 106 costs is not approved by the BPU, the impact on the financial position and results of operations would be material.

In accordance with SFAS 106 disclosure requirements, a reconciliation of the funded status of the plan is as follows:

	December 31,	
	1995	1994
	(Millions)	
Accumulated postretirement benefit obligation:		
Retirees .....	\$(444.6)	\$(379.2)
Fully eligible active plan participants .....	(52.9)	(45.7)
Other active plan participants .....	(220.4)	(161.0)
Total .....	(717.9)	(585.9)
Plan assets at fair value .....	—	—
Accumulated postretirement benefit obligation in excess of plan assets .....	(717.9)	(585.9)
Unrecognized net (gain)/loss from past experience different from that assumed and from changes in assumptions .....	32.8	(78.8)
Unrecognized prior service cost .....	—	—
Unrecognized transition obligation .....	517.9	548.3
Accrued postretirement obligation .....	<u>\$(167.2)</u>	<u>\$(116.4)</u>

The discount rate used in determining the accumulated postretirement benefit obligation as of December 31, 1995 was 7.25% and 8.50% for 1995 and 1994, respectively.

### Note 14. Pension Plan

The discount rates, expected long-term rates of return on assets and average compensation growth rates used in determining the Pension Plan's funded status and net pension cost as of December 31, 1995 and 1994 were as follows:

	1995	1994
Funded Status:		
Discount Rate used to Determine Benefit Obligations .....	7¼%	8½%
Average Compensation Growth to Determine Benefit Obligations .....	4.5%	4.5%
Net Pension Cost:		
Discount Rate .....	8.5%	7¼%
Expected Long-Term Return on Assets .....	8.5%	8%
Average Compensation Growth .....	4.5%	5.5%

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

The following table shows the Pension Plan's funded status:

	<u>December 31,</u>	
	<u>1995</u>	<u>1994</u>
	<u>(Thousands of Dollars)</u>	
Actuarial present value of benefit obligations:		
Accumulated benefit obligations, including vested benefits of \$1,403,313 in 1995 and \$1,151,677 in 1994 .....	\$(1,509,841)	\$(1,235,930)
Effect of projected future compensation .....	(321,545)	(261,846)
Projected benefit obligations .....	(1,831,386)	(1,497,776)
Plan assets at fair value, primarily listed equity and debt securities .....	1,533,446	1,270,116
Projected benefit obligations in excess of plan assets .....	(297,940)	(227,660)
Unrecognized net gain (loss) from past experience and effects of changes in assumptions .....	120,859	32,815
Prior service cost not yet recognized in net pension cost .....	110,213	119,783
Unrecognized net obligations being recognized over 16.7 years .....	61,287	69,387
Accrued pension expense .....	<u>\$ (5,581)</u>	<u>\$ (5,675)</u>

The net pension cost for the years ending December 31, 1995, 1994 and 1993, include the following components:

	<u>1995</u>	<u>1994</u>	<u>1993</u>
	<u>(Thousands of Dollars)</u>		
Service cost—benefits earned during year .....	\$ 37,033	\$ 42,904	\$ 42,948
Interest cost on projected benefit obligations .....	124,147	108,394	103,118
Return on assets .....	(312,190)	5,022	(166,916)
Net amortization and deferral .....	222,916	(90,752)	90,958
Total .....	<u>\$ 71,906</u>	<u>\$ 65,568</u>	<u>\$ 70,108</u>

See Note 1—Organization and Summary of Significant Accounting Policies.

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

## Note 15. Financial Information by Business Segments

Information related to the segments of Enterprise's business is detailed below:

	Electric	Gas	EDC	Nonutility Activities(A)	Total
	(Thousands of Dollars)				
<b>For the Year Ended December 31, 1995</b>					
Operating Revenues .....	\$ 4,020,842	\$1,686,403	\$248,002	\$ 208,906	\$ 6,164,153
Eliminations (Intersegment Revenues) ....	—	—	—	—	—
Total Operating Revenues .....	4,020,842	1,686,403	248,002	208,906	6,164,153
Depreciation and Amortization .....	503,022	88,092	77,265	5,852	674,231
Operating Income Before Income Taxes ...	1,140,279	178,718	58,654	142,172	1,519,823
Capital Expenditures .....	545,997	140,153	132,098	8,364	826,612
<b>December 31, 1995</b>					
Net Utility Plant .....	9,651,695	1,535,736	—	—	11,187,431
Oil and Gas Property, Plant & Equipment ..	—	—	608,015	—	608,015
Other Corporate Assets .....	2,778,691	589,455	147,822	1,858,654	5,374,622
Total Assets .....	\$12,430,386	\$2,125,191	\$755,837	\$1,858,654	\$17,170,068
<b>For the Year Ended December 31, 1994</b>					
Operating Revenues .....	\$ 3,739,713	\$1,778,528	\$229,880	\$ 187,067	\$ 5,935,188
Eliminations (Intersegment Revenues) ....	—	—	(11,179)	(1,566)	(12,745)
Total Operating Revenues .....	3,739,713	1,778,528	218,701	185,501	5,922,443
Depreciation and Amortization .....	471,910	79,462	78,567	4,089	634,028
Operating Income Before Income Taxes ...	1,083,155	226,196	39,210	133,590	1,482,151
Capital Expenditures .....	734,100	153,183	160,296	8,445	1,056,024
<b>December 31, 1994</b>					
Net Utility Plant .....	9,642,177	1,456,068	—	—	11,098,245
Oil and Gas Property, Plant & Equipment ..	—	—	577,913	—	577,913
Other Corporate Assets .....	2,589,348	576,806	150,973	1,724,155	5,041,282
Total Assets .....	\$12,231,525	\$2,032,874	\$728,886	\$1,724,155	\$16,717,440
<b>For the Year Ended December 31, 1993</b>					
Operating Revenues .....	\$ 3,696,114	\$1,594,341	\$278,470	\$ 161,650	\$ 5,730,575
Eliminations (Intersegment Revenues) ....	—	—	(20,158)	(1,827)	(21,985)
Total Operating Revenues .....	3,696,114	1,594,341	258,312	159,823	5,708,590
Depreciation and Amortization .....	441,164	69,375	86,136	4,922	601,597
Operating Income Before Income Taxes ...	1,117,739	173,916	92,162	43,310	1,427,127
Capital Expenditures .....	738,362	152,012	91,988	2,026	984,388
<b>December 31, 1993</b>					
Net Utility Plant .....	9,451,581	1,352,799	—	—	10,804,380
Oil and Gas Property, Plant & Equipment ..	—	—	506,047	—	506,047
Other Corporate Assets .....	2,313,394	866,524	173,390	1,665,921	5,019,229
Total Assets .....	\$11,764,975	\$2,219,323	\$679,437	\$1,665,921	\$16,329,656

(A) The Nonutility Activities include amounts applicable to Enterprise, the parent corporation.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Information related to Property, Plant and Equipment of PSE&G is detailed below:

	December 31,		
	1995	1994	1993
	(Thousands of Dollars)		
Utility Plant—Original Cost			
Electric Plant in Service			
Steam Production .....	\$ 1,791,010	\$ 1,810,674	\$ 1,763,253
Nuclear Production .....	5,992,341	5,931,049	5,873,274
Transmission .....	1,127,031	1,078,928	1,034,150
Distribution .....	3,044,830	2,877,862	2,724,202
Other .....	1,139,891	647,406	526,015
Total Electric Plant in Service .....	<u>13,095,103</u>	<u>12,345,919</u>	<u>11,920,894</u>
Gas Plant in Service			
Transmission .....	65,109	62,213	63,395
Distribution .....	2,250,705	2,131,816	1,993,044
Other .....	126,758	124,204	121,402
Total Gas Plant in Service .....	<u>2,442,572</u>	<u>2,318,233</u>	<u>2,177,841</u>
Common Plant in Service			
Capital Leases .....	58,610	58,610	56,812
General .....	458,494	486,521	463,473
Total Common Plant in Service .....	<u>517,104</u>	<u>545,131</u>	<u>520,285</u>
Total .....	<u>\$16,054,779</u>	<u>\$15,209,283</u>	<u>\$14,619,020</u>

### Note 16. Property Impairment of Enterprise Group Development Corporation

As a result of a management review of each property's current value and the potential for increasing such value through operating and other improvements, EGDC recorded an impairment in 1993 related to certain of its properties, including properties upon which EDHI's management revised its intent from a long-term investment strategy to a hold for sale status, reflecting such properties on its books at their net realizable value. This impairment reduced the estimated value of EGDC's properties by \$77.6 million and 1993 net income by \$50.5 million, after tax, or 21 cents per share of Enterprise Common Stock.

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## **Note 17. Jointly Owned Facilities—Utility Plant**

PSE&G has ownership interests in and is responsible for providing its share of the necessary financing for the following jointly owned facilities. All amounts reflect the share of PSE&G's jointly owned projects and the corresponding direct expenses are included in Consolidated Statements of Income as operating expenses. (See Note 1—Organization and Summary of Significant Accounting Policies.)

<u>Plant—December 31, 1995</u>	<u>Ownership Interest</u>	<u>Plant in Service</u>	<u>Accumulated Depreciation</u>	<u>Plant Under Construction</u>
			(Thousands of Dollars)	
Coal Generating				
Conemaugh .....	22.50%	\$ 198,724	\$ 38,339	\$2,401
Keystone .....	22.84	119,690	32,800	1,629
Nuclear Generating				
Peach Bottom .....	42.49	755,504	312,856	21,139
Salem .....	42.59	1,055,114	396,795	57,041
Hope Creek .....	95.00	4,122,715	1,063,403	13,592
Nuclear Support Facilities .....	Various	179,065	33,754	2,990
Pumped Storage Generating				
Yards Creek .....	50.00	27,246	9,293	2,350
Transmission Facilities .....	Various	121,100	36,266	89
Merrill Creek Reservoir .....	13.91	37,231	12,111	—
Linden Gas Plant .....	90.00	15,855	19,388	—

## **Note 18. Selected Quarterly Data (Unaudited)**

The information shown below, in the opinion of Enterprise, includes all adjustments, consisting only of normal recurring accruals, necessary to a fair presentation of such amounts. Due to the seasonal nature of the utility business, quarterly amounts vary significantly during the year.

<u>Calendar Quarter Ended</u>	<u>March 31,</u>		<u>June 30,</u>		<u>September 30,</u>		<u>December 31,</u>	
	<u>1995</u>	<u>1994</u>	<u>1995</u>	<u>1994</u>	<u>1995</u>	<u>1994</u>	<u>1995</u>	<u>1994</u>
	(Thousands Where Applicable)							
Operating Revenues .....	\$1,676,269	\$1,795,457	\$1,328,784	\$1,279,588	\$1,492,130	\$1,376,199	\$1,666,970	\$1,471,199
Operating Income .....	\$ 334,336	\$ 348,948	\$ 233,239	\$ 252,725	\$ 311,528	\$ 311,920	\$ 278,607	\$ 250,500
Net Income .....	\$ 212,592	\$ 230,127	\$ 110,667	\$ 129,885	\$ 186,782	\$ 187,178	\$ 152,282	\$ 131,843
Earnings Per Share of								
Common Stock .....	\$ 0.87	\$ 0.94	\$ 0.45	\$ 0.53	\$ 0.76	\$ 0.76	\$ 0.62	\$ 0.54
Average Shares of								
Common Stock								
Outstanding .....	244,698	243,777	244,698	244,698	244,698	244,698	244,698	244,698

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**PSE&G**

Except as modified below, the Notes to Consolidated Financial Statements of Enterprise are incorporated herein by reference insofar as they relate to PSE&G and its subsidiaries:

- Note 1. —Organization and Summary of Significant Accounting Policies
- Note 2. —Rate Matters
- Note 3. —PSE&G Nuclear Decommissioning and Amortization of Nuclear Fuel
- Note 4. —Schedule of Consolidated Capital Stock and Other Securities
- Note 5. —Deferred Items
- Note 6. —Schedule of Consolidated Debt
- Note 7. —Long-Term Investments
- Note 8. —Financial Instruments and Risk Management
- Note 11. —Leasing Activities—As Lessee
- Note 12. —Commitments and Contingent Liabilities
- Note 13. —Postretirement Benefits Other Than Pensions
- Note 14. —Pension Plan
- Note 15. —Financial Information by Business Segments
- Note 17. —Jointly Owned Facilities—Utility Plant

**Note 1. Organization and Summary of Significant Accounting Policies**

**Consolidation Policy**

The consolidated financial statements include the accounts of PSE&G and its subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. Certain reclassifications of prior years' data have been made to conform with the current presentation.

**Note 9. Cash and Cash Equivalents**

The December 31, 1995 and 1994 balances consist primarily of working funds.

**Note 10. Federal Income Taxes**

A reconciliation of reported Net Income with pretax income and of Federal income tax expense with the amount computed by multiplying pretax income by the statutory Federal income tax rate of 35% is as follows:

	<u>1995</u>	<u>1994</u>	<u>1993</u>
Net Income .....	\$616,964	\$659,406	\$614,868
Federal income taxes:			
Operating income:			
Current provision .....	275,460	230,709	177,314
Provision for deferred income taxes—net(A) .....	65,084	83,028	149,884
Investment tax credits—net .....	(19,111)	(19,208)	(18,408)
Total included in operating income .....	321,433	294,529	308,790
Miscellaneous other income:			
Current provision .....	(9,897)	(8,186)	(15,419)
Provision for deferred income taxes(A) .....	9,816	10,422	9,815
SFAS 90 deferred income taxes(A) .....	2,161	2,530	2,948
Total Federal income tax provisions .....	323,513	299,295	306,134
Pretax income .....	<u>\$940,477</u>	<u>\$958,701</u>	<u>\$921,002</u>

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

Reconciliation between total Federal income tax provisions and tax computed at the statutory tax rate on pretax income:

	<u>1995</u>	<u>1994</u>	<u>1993</u>
	<u>(Thousands of Dollars)</u>		
Tax expense at the statutory rate .....	<u>\$329,167</u>	<u>\$335,546</u>	<u>\$322,351</u>
Increase (decrease) attributable to flow-through of certain tax adjustments:			
Depreciation .....	16,257	(4,597)	3,347
Amortization of investment tax credits .....	(19,111)	(19,208)	(18,408)
Other .....	<u>(2,800)</u>	<u>(12,446)</u>	<u>(1,156)</u>
Subtotal .....	<u>(5,654)</u>	<u>(36,251)</u>	<u>(16,217)</u>
Total Federal income tax provisions .....	<u>\$323,513</u>	<u>\$299,295</u>	<u>\$306,134</u>
Effective Federal income tax rate .....	34.4%	31.2%	33.2%

(A) The provision for deferred income taxes represents the tax effects of the following items:

	<u>1995</u>	<u>1994</u>	<u>1993</u>
	<u>(Thousands of Dollars)</u>		
Deferred Credits:			
Additional tax depreciation and amortization .....	\$111,193	\$ 85,335	\$ 92,693
Property Abandonments .....	(7,411)	(6,606)	(6,632)
Oil and Gas Property Write-Down .....	(2,451)	(2,451)	(2,451)
Deferred fuel costs-net .....	(3,601)	39,361	63,330
Other .....	<u>(20,669)</u>	<u>(19,659)</u>	<u>15,707</u>
Total .....	<u>\$ 77,061</u>	<u>\$ 95,980</u>	<u>\$162,647</u>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

### SFAS 109

The following is an analysis of accumulated deferred income taxes:

<u>Accumulated Deferred Income Taxes</u>	1995	1994
	(Thousands of Dollars)	
<b>Assets:</b>		
Current (net) .....	\$ 27,571	\$ 25,311
Non-Current:		
Unrecovered Investment Tax Credits .....	129,713	136,402
Nuclear Decommissioning .....	25,241	25,082
Hope Creek Cost Disallowance .....	—	10,127
Construction Period Interest and Taxes .....	17,199	15,913
Vacation Pay .....	6,681	6,822
Other .....	5,057	6,863
Total Non-Current .....	<u>\$ 183,891</u>	<u>\$ 201,209</u>
Total Assets .....	<u>\$ 211,462</u>	<u>\$ 226,520</u>
<b>Liabilities:</b>		
Non-Current:		
Plant Related Items .....	\$2,237,386	\$2,157,206
Property Abandonments .....	21,469	26,971
Oil and Gas Property Write-Down .....	13,061	14,925
Deferred Electric Energy & Gas Costs .....	56,283	59,884
Unamortized Debt Expense .....	36,945	37,599
Taxes Recoverable Through Future Rates (Net) .....	262,625	270,684
Other .....	91,725	112,479
Total Non-Current .....	<u>\$2,719,494</u>	<u>\$2,679,748</u>
Total Liabilities .....	<u>\$2,719,494</u>	<u>\$2,679,748</u>
<b>Summary—Accumulated Deferred Income Taxes</b>		
Net Current Assets .....	\$ 27,571	\$ 25,311
Net Deferred Liability .....	<u>\$2,535,603</u>	<u>\$2,478,539</u>
Total .....	<u>\$2,500,032</u>	<u>\$2,453,228</u>

The balance of Federal income tax payable by PSE&G to Enterprise was \$5.3 million and \$15.6 million, as of December 31, 1995 and December 31, 1994, respectively.

# **NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## **Note 18. Selected Quarterly Data (Unaudited)**

The information shown below, in the opinion of PSE&G, includes all adjustments, consisting only of normal recurring accruals, necessary to a fair presentation of such amounts. Due to the seasonal nature of the utility business, quarterly amounts vary significantly during the year.

Calendar Quarter ended	March 31,		June 30,		September 30,		December 31,	
	1995	1994	1995	1994	1995	1994	1995	1994
	(Thousands of Dollars)							
Operating Revenues .....	\$1,579,516	\$1,690,999	\$1,235,435	\$1,182,880	\$1,381,004	\$1,284,175	\$1,511,290	\$1,360,187
Operating Income .....	\$ 298,432	\$ 305,013	\$ 204,606	\$ 218,225	\$ 280,525	\$ 282,782	\$ 211,939	\$ 206,650
Net Income .....	\$ 206,896	\$ 221,439	\$ 111,300	\$ 128,113	\$ 184,878	\$ 190,378	\$ 113,890	\$ 119,476
Earnings Available to								
Public Service								
Enterprise Group								
Incorporated .....	\$ 198,214	\$ 211,159	\$ 102,620	\$ 117,969	\$ 176,196	\$ 180,234	\$ 105,698	\$ 109,577

## **Note 19. Accounts Payable to Associated Companies—Net**

The balance at December 31, 1995 and 1994 consisted of the following:

	1995	1994
	(Thousands of Dollars)	
Public Service Enterprise Group Incorporated (A) .....	\$ 9,055	\$17,678
Energy Development Corporation .....	(306)	(336)
Other .....	(738)	(665)
Total .....	<u>\$ 8,011</u>	<u>\$16,677</u>

(A) Principally Federal income taxes related to PSE&G's taxable income.

## **PART III**

### **Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

Enterprise and PSE&G, none.

### **Item 10. Directors and Executive Officers of the Registrants**

#### **Directors of the Registrants**

##### **Enterprise**

The information required by Item 10 of Form 10-K with respect to present directors who are nominees for election as directors at Enterprise's Annual Meeting of Stockholders to be held on April 16, 1996, and directors whose terms will continue beyond the meeting, is set forth under the heading "Election of Directors" in Enterprise's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 1, 1996 and which information set forth under said heading is incorporated herein by this reference thereto.

##### **PSE&G**

There is shown as to each present director information as to the period of service as a director of PSE&G, age as of April 16, 1996, present committee memberships, business experience during the last five years and other present directorships. For discussion of certain litigation involving the directors of PSE&G, except Forrest J. Remick, see Part I—Business, Item 3—Legal Proceedings.

LAWRENCE R. CODEY has been a director since 1988. Age 51. Member of Executive Committee. Has been President and Chief Operating Officer of PSE&G since September 1991. Was Senior Vice President—Electric of PSE&G from January 1989 to September 1991. Director of Enterprise. Director of Sealed Air Corporation, The Trust Company of New Jersey, United Water Resources Inc. and Blue Cross & Blue Shield of New Jersey.

E. JAMES FERLAND has been a director since 1986. Age 54. Chairman of Executive Committee. Chairman of the Board, President and Chief Executive Officer of Enterprise since July 1986, Chairman of the Board and Chief Executive Officer of PSE&G since September 1991 and Chairman of the Board and Chief Executive Officer of EDHI since June 1989. President of PSE&G from July 1986 to September 1991. Director of Enterprise and of EDHI and its principal subsidiaries. Director of Foster Wheeler Corporation and The Hartford Steam Boiler Inspection and Insurance Company.

RAYMOND V. GILMARTIN has been a director since 1993. Age 55. Director of Enterprise. Has been Chairman of the Board, President and Chief Executive Officer of Merck & Co., Inc., Whitehouse Station, New Jersey (discovers, develops, produces and markets human and animal health products) since November 1994. Was President and Chief Executive Officer from June 1994 to November 1994. Was Chairman of the Board, President and Chief Executive Officer of Becton Dickinson and Company from November 1992 to June 1994 and President and Chief Executive Officer from February 1989 to November 1992. Director of Merck & Co., Inc. and Providian Corporation.

IRWIN LERNER has been a director since 1993. Age 65. Was previously a director from 1981 to February 1988. Director of Enterprise. Was Chairman, Board of Directors and Executive Committee from January 1993 to September 1993 and President and Chief Executive Officer from 1980 to December 1992 of Hoffmann-La Roche Inc., Nutley, New Jersey (prescription pharmaceuticals, vitamins and fine chemicals, and diagnostic products and services). Director of Humana Inc., Sequana Therapeutics, Inc. and Medarex, Inc.

JAMES C. PITNEY has been a director since 1993. Age 69. Was previously a director from 1979 to February 1988. Member of Executive Committee. Director of Enterprise. Has been a partner in the law firm of Pitney, Hardin, Kipp & Szuch, Morristown, New Jersey, since 1958. Director of Tri-Continental Corporation, sixteen funds of the Seligman family of funds and Seligman Quality, Inc.

FORREST J. REMICK has been a director since May 1995. Age 65. Director of Enterprise. Has been an engineering consultant since July 1994. Was Commissioner, United States Nuclear Regulatory Commission, from December 1989 to June 1994. Was Associate Vice President—Research and Professor of Nuclear Engineering at Pennsylvania State University, from 1985 to 1989.

#### Executive Officers of the Registrants

The following table sets forth certain information concerning the executive officers of Enterprise and PSE&G, respectively.

<u>Name</u>	<u>Age December 31, 1995</u>	<u>Office</u>	<u>Effective Date First Elected to Present Position</u>
E. James Ferland . .	53	Chairman of the Board, President and Chief Executive Officer (Enterprise)	July 1986 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	July 1986 to present
		President (PSE&G)	June 1986 to September 1991
		Chairman of the Board and Chief Executive Officer (EDHI)	June 1989 to present
Lawrence R. Codey .	51	President and Chief Operating Officer (PSE&G)	September 1991 to present
		Senior Vice President—Electric (PSE&G)	January 1989 to September 1991
Robert C. Murray . .	50	Vice President and Chief Financial Officer (Enterprise)	January 1992 to present
		Senior Vice President and Chief Financial Officer (PSE&G)	January 1992 to present
		Managing Director of Morgan Stanley & Co. Incorporated	January 1987 to July 1991
Patricia A. Rado . . .	53	Vice President and Controller (Enterprise)	April 1993 to present
		Vice President and Controller (PSE&G)	April 1993 to present
		Controller of Yankee Energy Systems Inc.	July 1989 to April 1993
Paul H. Way . . . . .	58	President, Chief Operating Officer and Director (EDHI)	February 1993 to present
		Senior Vice President (EDHI)	June 1992 to February 1993
		Senior Vice President—Corporate Performance (PSE&G)	April 1988 to June 1992
R. Edwin Selover . .	50	Vice President and General Counsel (Enterprise)	April 1988 to present
		Senior Vice President and General Counsel (PSE&G)	January 1988 to present

<u>Name</u>	<u>Age December 31, 1995</u>	<u>Office</u>	<u>Effective Date First Elected to Present Position</u>
Robert J. Dougherty, Jr.	44	President—Enterprise Ventures and Services Corporation (PSE&G)	February 1995 to present
		Senior Vice President—Electric (PSE&G)	September 1991 to February 1995
		Senior Vice President—Customer Operations (PSE&G)	September 1989 to September 1991
Leon R. Eliason . . . . .	56	Chief Nuclear Officer and President—Nuclear Business Unit (PSE&G)	October 1994 to present
		President, Power Supply Business Unit, Northern States Power	January 1993 to September 1994
		Vice President, Nuclear Generation, Northern States Power	July 1990 to January 1993
Alfred C. Koeppe . . . .	49	Senior Vice President— External Affairs (PSE&G)	October 1995 to present
		President and Chief Executive Officer of Bell Atlantic—New Jersey	February 1993 to October 1995
		Vice President—Public Affairs of Bell Atlantic—New Jersey	February 1991 to February 1993

## Item 11. Executive Compensation

### Enterprise

The information required by Item 11 of Form 10-K is set forth under the heading "Executive Compensation" in Enterprise's definitive Proxy Statement for the Annual Meeting of Stockholders to be held April 16, 1996, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 1, 1996 and such information set forth under such heading is incorporated herein by this reference thereto.

### PSE&G

Information regarding the compensation of the Chief Executive Officer and the four most highly compensated executive officers of PSE&G as of December 31, 1995 is set forth below. Amounts shown were paid or awarded for all services rendered to Enterprise and its subsidiaries and affiliates including PSE&G.

**SUMMARY COMPENSATION TABLE**

Name and Principal Position	Year	Annual Compensation		Long-Term Compensation		All Other Compensation (\$)(4)
		Salary \$	Bonus/Annual Incentive Award \$(1)	Awards Securities Underlying Options (#)(2)	Payouts LTIP Payouts \$(3)	
E. James Ferland .....	1995	682,377	(5)	5,800	246,288	8,681
Chairman of the Board,	1994	652,492	251,383	5,400	127,140	5,628
President and CEO of Enterprise	1993	622,606	265,316	5,800	28,072	7,678
Lawrence R. Codey .....	1995	418,392	(5)	2,800	118,746	5,756
President and Chief	1994	398,468	129,276	2,500	48,900	5,351
Operating Officer of PSE&G	1993	378,545	109,585	2,800	9,570	6,981
Leon R. Eliason .....	1995	323,755	165,000(5)(6)	5,500	26,388	3,242
President—Nuclear	1994	74,713	0	600	0	0
Business Unit of PSE&G and Chief Nuclear Officer(7)	1993	0	0	0	0	0
Robert J. Dougherty, Jr. ....	1995	322,759	(5)	2,500	70,368	4,269
Vice President of Enterprise and President of Enterprise Ventures and Services Corporation	1994	273,946	72,027	1,800	26,895	4,227
	1993	259,004	65,703	2,000	5,104	6,341
Robert C. Murray .....	1995	318,775	25,000(5)(8)	2,000	70,368	5,169
Vice President and Chief Financial Officer of Enterprise	1994	303,832	152,621(8)	1,800	26,895	4,944
	1993	288,889	154,032(8)	2,000	3,190	7,264

- (1) Amount awarded in given year was earned under Management Incentive Compensation Plan (MICP) and determined in following year with respect to the given year based on individual performance and financial and operating performance of Enterprise and PSE&G, including comparison to other companies. Award is accounted for as market-priced phantom stock with dividend reinvestment at 95% of market price, with payment made over three years beginning in second year following grant.
- (2) Granted under Long-Term Incentive Plan (LTIP) in tandem with equal number of performance units and dividend equivalents which may provide cash payments, dependent upon future financial performance of Enterprise in comparison to other companies and dividend payments by Enterprise, to assist officers in exercising options granted. The grant is made at the beginning of a three-year performance period and cash payment of the value of such performance units and dividend equivalents is made following such period in proportion to the options, if any, exercised at such time.

- (3) Amount paid in proportion to options exercised, if any, based on value of previously granted performance units and dividend equivalents, each as measured during three-year period ending the year prior to the year in which payment is made.
- (4) Includes employer contribution to Thrift and Tax-Deferred Savings Plan and value of 5% discount on phantom stock dividend reinvestment under MICP:

	<u>Ferland</u>		<u>Codey</u>		<u>Eliason</u>		<u>Dougherty</u>		<u>Murray</u>	
	<u>Thrift</u>	<u>MICP</u>	<u>Thrift</u>	<u>MICP</u>	<u>Thrift</u>	<u>MICP</u>	<u>Thrift</u>	<u>MICP</u>	<u>Thrift</u>	<u>MICP</u>
	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>	<u>(\$)</u>
1995 .....	3,752	2,383	4,502	1,254	1,795	0	3,754	515	4,502	667
1994 .....	3,751	1,877	4,197	1,154	0	0	3,752	475	4,504	440
1993 .....	5,900	1,778	5,896	1,085	0	0	5,907	434	7,078	186

In addition, for Mr. Ferland and Mr. Eliason, 1995 amounts include \$2,546 and \$1,447, respectively, representing interest on compensation deferred under PSE&G's Deferred Compensation Plan in excess of 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Internal Revenue Code. Under PSE&G's Deferred Compensation Plan, interest is paid at prime rate plus 1/2%, adjusted quarterly.

- (5) The 1995 MICP award amount has not yet been determined. The target award is 40% of salary for Mr. Ferland, 30% for Messrs. Codey, Eliason and Dougherty and 25% for Mr. Murray. The target award is adjusted to reflect Enterprise's return on capital, PSE&G's comparative electric and gas costs and individual performance.
- (6) Amount paid pursuant to Mr. Eliason's employment agreement.
- (7) Mr. Eliason commenced employment September 26, 1994.
- (8) 1995 amount paid pursuant to Mr. Murray's employment agreement. 1994 and 1993 amounts include \$50,000 and \$75,000, respectively, paid pursuant to Mr. Murray's employment agreement.

### OPTION GRANTS IN LAST FISCAL YEAR (1995)

Name	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term(2)		
	Number of Securities Underlying Options Granted(1)	% of Total Options Granted to Employees in Fiscal Year	Exercise or Base Price (\$/Sh)	Expiration Date	0%(\$)	5%(\$)	10%(\$)
E. James Ferland .....	5,800	16.6	26.625	1/04/05	0	97,117	246,114
Lawrence R. Codey .....	2,800	8.0	26.625	1/04/05	0	46,884	118,874
Leon R. Eliason .....	2,500		26.625	1/04/05	0	41,861	106,083
	1,800	(15.7)	31.375	1/04/05	0	35,517	90,007
	1,200		30.500	1/04/05	0	23,018	58,331
Robert J. Dougherty, Jr. ....	2,000	(7.1)	26.625	1/04/05	0	33,489	84,867
	500		28.125	3/02/05	0	8,844	22,412
Robert C. Murray .....	2,000	5.7	26.625	1/04/05	0	33,489	84,867

- (1) Granted under LTIP in tandem with equal number of performance units and dividend equivalents which may provide cash payments, dependent on future financial performance of Enterprise in comparison to other companies and dividend payments by Enterprise, to assist individuals in exercising options, with exercisability commencing January 1, 1998, except with respect to Mr. Eliason, for whom exercisability commences January 1, 1996, 1997 and 1998, respectively, for each of his three grants. Cash payment is made, based on the value, if any, of performance units awarded and dividend equivalents accrued, if any, as measured during the three-year period ending the year prior to the year in which payment, if any, is made, only if the specified performance level is achieved, dividend equivalents have accrued and options are exercised.
- (2) All options reported have a ten-year term, as noted. Amounts shown represent hypothetical future values at such term based upon hypothetical price appreciation of Enterprise Common Stock and may not necessarily be realized. Actual values which may be realized, if any, upon any exercise of such options, will be based on the market price of Enterprise Common Stock at the time of any such exercise and thus are dependent upon future performance of Enterprise Common Stock.

### AGGREGATED OPTION EXERCISES IN LAST FISCAL YEAR (1995) AND FISCAL YEAR-END OPTION VALUES (12/31/95)

Name	Shares Acquired on Exercise (#)(1)	Value Realized (\$)(2)	Number of Unexercised Options At Fy-End(#)(1)		Value of Unexercised In-The-Money Options At Fy-End(\$)(3)	
			Exercisable (#)	Unexercisable (#)	Exercisable (\$)	Unexercisable (\$)
E. James Ferland .....	5,600	0	0	17,000	0	23,925
Lawrence R. Codey .....	2,700	0	700	8,100	4,463	11,550
Leon R. Eliason .....	600	72	0	5,500	0	10,150
Robert J. Dougherty .....	1,600	0	0	6,300	0	9,500
Robert C. Murray .....	1,600	192	0	5,800	0	8,250

- (1) Does not reflect any options granted and/or exercised after year-end (12/31/95). The net effect of any such grants and exercises is reflected in the table appearing under Security Ownership of Directors and Management.
- (2) Represents difference between exercise price and market price of Enterprise Common Stock on date of exercise.
- (3) Represents difference between market price of Enterprise Common Stock and the respective exercise prices of the options at fiscal year-end (12/31/95). Such amounts may not necessarily be realized. Actual values which may be realized, if any, upon any exercise of such options will be based on the market price of Enterprise Common Stock at the time of any such exercise and thus are dependent upon future performance of Enterprise Common Stock.

## **Employment Contracts and Arrangements**

Employment agreements were entered into with Messrs. Ferland, Eliason and Murray at the time of their employment. For Mr. Ferland, the remaining applicable provisions of the agreement provide for additional credited service for pension purposes in the amount of 22 years. The principal remaining applicable terms of the agreement with Mr. Eliason provide for payment of severance in the amount of one year's salary, if discharged without cause during his first five years of employment which began in September 1994, for lump sum cash payments of \$100,000 in 1996, \$65,000 in 1997 and \$35,000 in 1998 to align Mr. Eliason with MICP payments for other executive officers, and additional years of credited service for pension purposes for allied work experience of 19 years after completion of three years of service, and up to 29 years after completion of ten years of service. The principal remaining applicable terms of the agreement with Mr. Murray provide for payment of severance in the amount of one year's salary, if discharged without cause during his first five years of employment, which began in January 1992, and additional years of credited service for pension purposes for allied work experience of five years after completion of five years of service, and up to fifteen years after completion of ten years of service.

## **Compensation Committee Interlocks and Insider Participation**

PSE&G does not have a compensation committee. Decisions regarding compensation of PSE&G's executive officers are made by the Organization and Compensation Committee of Enterprise. Hence, during 1995 the PSE&G Board of Directors did not have, and no officer, employee or former officer of PSE&G participated in any deliberations of such Board, concerning executive officer compensation.

## **Compensation of Directors and Certain Business Relationships**

A director who is not an officer of Enterprise or its subsidiaries and affiliates, including PSE&G, is paid an annual retainer of \$22,000 and a fee of \$1,200 for attendance at any Board or committee meeting, inspection trip, conference or other similar activity relating to Enterprise, PSE&G or EDHL. Each of the directors of PSE&G is also a director of Enterprise. No additional retainer is paid for service as a director of PSE&G. Fifty percent of the annual retainer is paid in Enterprise Common Stock.

Enterprise also maintains a Stock Plan for Outside Directors pursuant to which directors who are not employees of Enterprise or its subsidiaries receive 300 shares of restricted stock for each year of service as a director. Such shares held by each non-employee director are included in the table above under the heading Security Ownership of Directors and Management. Prior to 1996, Enterprise had maintained a retirement plan for non-employee directors which provided an annual benefit for life equal to the annual Board retainer in effect at the time the director's service terminated if the director retired from the Board after 10 years of service. Participation of all current directors under that plan was terminated December 31, 1995. As of January 1, 1996, current non-employee directors with ten years or more of service received an award of shares of restricted stock equal to the present value of the retirement benefit under this prior retirement plan, while those with less than ten years of service received an award of 300 shares per year of service. The number of shares awarded were as follows: Mr. Gilmartin: 900; Mr. Lerner: 3,768; Mr. Pitney: 5,467; and Dr. Remick: 300. No current director remains eligible to receive a benefit under the prior retirement plan.

The restrictions on the stock granted under the Stock Plan for Outside Directors provide that the shares are subject to forfeiture if the director leaves service at any time prior to the Annual Meeting of Stockholders following his or her 70th birthday. This restriction would be deemed to have been satisfied if the director's service were terminated if Enterprise were to merge with another corporation and not be the surviving corporation or if the director were to die in office. Enterprise also has the ability to waive this restriction for good cause shown. Restricted stock may not be sold or otherwise transferred prior to the lapse of the restrictions. Dividends on shares held subject to restrictions are paid directly to the director, and the director has the right to vote the shares.

## Compensation Pursuant to Pension Plans

PENSION PLAN TABLE

Average Final Compensation	Length of Service			
	30 Years	35 Years	40 Years	45 Years
\$ 300,000	\$180,000	\$195,000	\$210,000	\$225,000
400,000	240,000	260,000	280,000	300,000
500,000	300,000	325,000	350,000	375,000
600,000	360,000	390,000	420,000	450,000
700,000	420,000	455,000	490,000	525,000
800,000	480,000	520,000	560,000	600,000
900,000	540,000	585,000	630,000	675,000
1,000,000	600,000	650,000	700,000	750,000

The above table illustrates annual retirement benefits expressed in terms of single life annuities based on the average final compensation and service shown and retirement at age 65. A person's annual retirement benefit is based upon a percentage that is equal to years of credited service plus 30, but not more than 75%, times average final compensation at the earlier of retirement, attainment of age 65 or death. These amounts are reduced by Social Security benefits and certain retirement benefits from other employers. Pensions in the form of joint and survivor annuities are also available.

Average final compensation, for purposes of retirement benefits of executive officers, is generally equivalent to the average of the aggregate of the salary and bonus amounts reported in the Summary Compensation Table above under 'Annual Compensation' for the five years preceding retirement, not to exceed 120% of the average annual salary for such five year period. Messrs. Ferland, Codey, Eliason, Dougherty and Murray will have accrued approximately 48, 41, 44, 48 and 39 years of credited service, respectively, as of age 65.

### Item 12. Security Ownership of Certain Beneficial Owners and Management

#### Enterprise

The information required by Item 12 of Form 10-K with respect to directors and executive officers is set forth under the heading 'Security Ownership of Directors and Management' in Enterprise's definitive Proxy Statement for the Annual Meeting of Stockholders to be held April 16, 1996 which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 1, 1996 and such information set forth under such heading is incorporated herein by this reference thereto.

#### PSE&G

All of PSE&G's 132,450,344 outstanding shares of Common Stock are owned beneficially and of record by PSE&G's parent, Enterprise, 80 Park Plaza, P.O. Box 1171, Newark, New Jersey.

The following table sets forth beneficial ownership of Enterprise Common Stock, including options, by the directors and executive officers named below as of January 31, 1995. None of these amounts exceed 1% of the Enterprise Common Stock outstanding at such date. No director or executive officer owns any PSE&G Preferred Stock of any class.

<u>Name</u>	<u>Amount and Nature of Beneficial Ownership</u>
Lawrence R. Codey .....	21,611(1)
Robert J. Dougherty, Jr. ....	13,588(2)
Leon R. Eliason .....	8,600(3)
E. James Ferland .....	63,479(4)
Raymond V. Gilmartin .....	2,347
Irwin Lerner .....	8,071
Robert C. Murray .....	13,752(5)
James C. Pitney .....	8,864
Forrest J. Remick .....	676
All directors and executive officers (12) as a group .....	157,582(6)

- (1) Includes options to purchase 11,800 additional shares, 3,500 of which are currently exercisable.
- (2) Includes the equivalent of 686 shares held under Thrift and Tax-Deferred Savings Plan. Include options to purchase 8,900 additional shares, 2,000 of which are currently exercisable.
- (3) Includes options to purchase 8,000 additional shares, 1,200 of which are currently exercisable.
- (4) Includes the equivalent of 9,432 shares held under Thrift and Tax-Deferred Savings Plan. Includes options to purchase 23,500 additional shares, 5,800 of which are currently exercisable.
- (5) Includes the equivalent of 752 shares held under Thrift and Tax-Deferred Savings Plan. Includes options to purchase 7,800 additional shares, 2,000 of which are currently exercisable.
- (6) Includes the equivalent of 10,870 shares held under Thrift and Tax-Deferred Savings Plan. Includes options to purchase 71,700 additional shares, of which 18,700 are currently exercisable.

### **Item 13. Certain Relationships and Related Transactions**

#### **Enterprise**

The information required by Item 13 of Form 10-K is set forth under the heading "Executive Compensation" in Enterprise's definitive Proxy Statement for the Annual Meeting of Stockholders to be held April 16, 1996, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 1, 1996. Such information set forth under such heading is incorporated herein by this reference thereto.

#### **PSE&G**

None.

## **PART IV**

### **Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K**

#### **(a) Financial Statements:**

- (1) Enterprise Consolidated Statements of Income for the years ended December 31, 1995, 1994, and 1993, on page 59.

Enterprise Consolidated Balance Sheets for the years ended December 31, 1995 and 1994, on pages 60 and 61.

Enterprise Consolidated Statements of Cash Flows for the years ended December 31, 1995, 1994, and 1993 on page 62.

Enterprise Statements of Retained Earnings for the years ended December 31, 1995, 1994, and 1993 on page 63.

Enterprise Notes to Consolidated Financial Statements on pages 70 through 101.

- (2) PSE&G Consolidated Statements of Income for the years ended December 31, 1995, 1994, and 1993, on page 65.

PSE&G Consolidated Balance Sheets for the years ended December 31, 1995 and 1994, on pages 66 and 67.

PSE&G Consolidated Statements of Cash Flows for the years ended December 31, 1995, 1994, and 1993 on page 68.

PSE&G Statements of Retained Earnings for the years ended December 31, 1995, 1994, and 1993 on page 69.

PSE&G Notes to Consolidated Financial Statements on pages 102 through 105.

#### **(b) The following documents are filed as a part of this report:**

- (1) Enterprise Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 1995 (page 117).

- (2) PSE&G Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 1995 (page 118).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

#### **(c) The following exhibits are filed herewith:**

- (1) Enterprise:

10a(18) —Directors Stock Plan

10a(19) —Mid Career Hire Supplemental Retirement Income Plan

10a(20) —Retirement Income Reinstatement Plan

12 —Computation of Ratios of Earnings to Fixed Charges.

21 —Subsidiaries of Registrant.

23 —Independent Auditors' Consent.

27 —Financial Data Schedule

(See Exhibit Index on pages 121 through 128).

(2) PSE&G:

- 10a(18) —Directors Stock Plan
- 10a(19) —Mid Career Hire Supplemental Retirement Income Plan
- 10a(20) —Retirement Income Reinstatement Plan
- 12(a) —Computation of Ratios of Earnings to Fixed Charges.
- 12(b) —Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements.
- 23 —Independent Auditors' Consent.
- 27 —Financial Data Schedule

(See Exhibit Index on page 121 and pages 129 through 135).

(d) The following reports on Form 8-K were filed by the registrant(s) named below during the last quarter of 1995 and the 1996 period covered by this report under Item 5:

<u>Registrant</u>	<u>Date of Report</u>	<u>Item Reported</u>
Enterprise and PSE&G	January 19, 1996	Item 5. Other Events (Alternative Rate Plan and change in credit agency rating)
Enterprise and PSE&G	December 12, 1995	Item 5. (Nuclear Operations—Salem and Energy Development Corporation Divestiture)
Enterprise and PSE&G	October 17, 1995	Item 5. Other Events (Nuclear Operations—Salem)

SCHEDULE II

**PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED**

**SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS**

**Years Ended December 31, 1995—December 31, 1993**

Column A	Column B	Column C		Column D	Column E
Description	Balance at beginning of period	Additions		Deductions-describe	Balance at end of period
		Charged to cost and expenses	Charged to other accounts-described		
(Thousands of Dollars)					
1995					
Allowance for Doubtful Accounts . . . . .	\$40,915	\$32,555	\$ —	\$35,829(A)	\$37,641
Discount on Property Abandonments . . .	\$11,423	\$ —	\$ —	\$ 3,957(B)	\$ 7,466
Inventory Valuation Reserve . . . . .	\$18,200	\$ 1,900	\$ —	\$ —	\$20,100
Valuation Allowances . . . . .	\$40,368	\$ 4,241	\$ —	\$15,079(C)	\$29,530
1994					
Allowance for Doubtful Accounts . . . . .	\$27,932	\$50,140	\$ —	\$37,157(A)	\$40,915
Discount on Property Abandonments . . .	\$16,263	\$ —	\$ —	\$ 4,840(B)	\$11,423
Inventory Valuation Reserve . . . . .	\$ 8,525	\$ 9,675	\$ —	\$ —	\$18,200
Valuation Allowances . . . . .	\$34,703	\$ 6,827	\$4,500	\$ 5,662	\$40,368
1993					
Allowance for Doubtful Accounts . . . . .	\$24,059	\$31,625	\$ —	\$27,752(A)	\$27,932
Discount on Property Abandonments . . .	\$21,951	\$ —	\$ —	\$ 5,688(B)	\$16,263
Inventory Valuation Reserve . . . . .	\$ —	\$ 8,525	\$ —	\$ —	\$ 8,525
Valuation Allowances . . . . .	\$21,509	\$17,887	\$ —	\$ 4,693	\$34,703

NOTES:

- (A) Accounts Receivable/Investments written off.
- (B) Amortization of discount to income.
- (C) Assets Sold

**SCHEDULE II**

**PUBLIC SERVICE ELECTRIC AND GAS COMPANY**

**SCHEDULE II—VALUATION AND QUALIFYING ACCCOUNTS**

**Years Ended December 31, 1995—December 31, 1993**

Column A	Column B	Column C		Column D	Column E
Description	Balance at beginning of period	Additions		Deductions—describe	Balance at end of period
		Charged to cost and expenses	Charged to other accounts—described		
(Thousands of Dollars)					
1995					
Allowance for Doubtful Accounts ...	\$40,915	\$ 32,555	\$—	\$35,829(A)	\$37,641
Discount on Property Abandonments.	\$11,423	\$ —	\$—	\$ 3,957(B)	\$ 7,466
Inventory Valuation Reserve.....	\$18,200	\$ 1,900	\$—	\$ —	\$20,100
1994					
Allowance for Doubtful Accounts ...	\$27,932	\$ 50,140	\$—	\$37,157(A)	\$40,915
Discount on Property Abandonments.	\$16,263	\$ —	\$—	\$ 4,840(B)	\$11,423
Inventory Valuation Reserve.....	\$ 8,525	\$ 9,675	\$—	\$ —	\$18,200
1993					
Allowance for Doubtful Accounts ...	\$24,059	\$ 31,625	\$—	\$27,752(A)	\$27,932
Discount on Property Abandonments.	\$21,951	\$ —	\$—	\$ 5,688(B)	\$16,263
Inventory Valuation Reserve.....	\$ —	\$ 8,525	\$—	\$ —	\$ 8,525

**NOTES:**

(A) Accounts Receivable/Investments written off.

(B) Amortization of discount to income.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By E. JAMES FERLAND  
**E. James Ferland**  
**Chairman of the Board, President**  
**and Chief Executive Officer**

Date: February 22, 1996

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>E. JAMES FERLAND</u> E. James Ferland	Chairman of the Board, President and Chief Executive Officer and Director (Principal Executive Officer)	February 22, 1996
<u>ROBERT C. MURRAY</u> Robert C. Murray	Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 1996
<u>PATRICIA A. RADO</u> Patricia A. Rado	Vice President and Controller (Principal Accounting Officer)	February 22, 1996
<u>LAWRENCE R. CODEY</u> Lawrence R. Codey	Director	February 22, 1996
<u>ERNEST H. DREW</u> Ernest H. Drew	Director	February 22, 1996
<u>T. J. DERMOT DUNPHY</u> T. J. Dermot Dunphy	Director	February 22, 1996
<u>RAYMOND V. GILMARTIN</u> Raymond V. Gilmartin	Director	February 22, 1996
<u>IRWIN LERNER</u> Irwin Lerner	Director	February 22, 1996
<u>MARILYN M. PFALTZ</u> Marilyn M. Pfaltz	Director	February 22, 1996
<u>JAMES C. PITNEY</u> James C. Pitney	Director	February 22, 1996
<u>FORREST J. REMICK</u> Forrest J. Remick	Director	February 22, 1996
<u>RICHARD J. SWIFT</u> Richard J. Swift	Director	February 22, 1996
<u>JOSH S. WESTON</u> Josh S. Weston	Director	February 22, 1996

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By E. JAMES FERLAND  
**E. James Ferland**  
**Chairman of the Board and**  
**Chief Executive Officer**

Date: February 22, 1996

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>E. JAMES FERLAND</u> <b>E. James Ferland</b>	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 22, 1996
<u>ROBERT C. MURRAY</u> <b>Robert C. Murray</b>	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 1996
<u>PATRICIA A. RADO</u> <b>Patricia A. Rado</b>	Vice President and Controller (Principal Accounting Officer)	February 22, 1996
<u>LAWRENCE R. CODEY</u> <b>Lawrence R. Codey</b>	Director	February 22, 1996
<u>RAYMOND V. GILMARTIN</u> <b>Raymond V. Gilmartin</b>	Director	February 22, 1996
<u>IRWIN LERNER</u> <b>Irwin Lerner</b>	Director	February 22, 1996
<u>JAMES C. PITNEY</u> <b>James C. Pitney</b>	Director	February 22, 1996
<u>FORREST J. REMICK</u> <b>Forrest J. Remick</b>	Director	February 22, 1996

## EXHIBIT INDEX

Certain Exhibits previously filed with the Commission and the appropriate securities exchanges are indicated as set forth below. Such Exhibits are not being refiled, but are included because inclusion is desirable for convenient reference.

(a) Filed by PSE&G with Form 8-A under the Securities Exchange Act of 1934, on the respective dates indicated, File No. 1-973.

(b) Filed by PSE&G with Form 8-K under the Securities Exchange Act of 1934, on the respective dates indicated, File No. 1-973.

(c) Filed by PSE&G with Form 10-K under the Securities Exchange Act of 1934, on the respective dates indicated, File No. 1-973.

(d) Filed by PSE&G with Form 10-Q under the Securities Exchange Act of 1934, on the respective dates indicated, File No. 1-973.

(e) Filed by Enterprise with Form 10-K under the Securities Exchange Act of 1934, on the respective dates indicated, File No. 1-9120.

(f) Filed with registration statement of PSE&G under the Securities Exchange Act of 1934, File No. 1-973, effective July 1, 1935, relating to the registration of various issues of securities.

(g) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-4995, effective May 20, 1942, relating to the issuance of \$15,000,000 First and Refunding Mortgage Bonds, 3% Series due 1972.

(h) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-7568, effective July 1, 1948, relating to the proposed issuance of 200,000 shares of Cumulative Preferred Stock.

(i) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-8381, effective April 18, 1950, relating to the issuance of \$26,000,000 First and Refunding Mortgage Bonds, 2¾% Series due 1980.

(j) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-12906, effective December 4, 1956, relating to the issuance of 1,000,000 shares of Common Stock.

(k) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-59675, effective September 1, 1977, relating to the issuance of \$60,000,000 First and Refunding Mortgage Bonds, 8½% Series I due 2007.

(l) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-60925, effective March 30, 1978, relating to the issuance of 750,000 shares of Common Stock through an Employee Stock Purchase Plan.

(m) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-65521, effective October 10, 1979, relating to the issuance of 3,000,000 shares of Common Stock.

(n) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 2-74018, filed on June 16, 1982, relating to the Thrift Plan of PSE&G.

(o) Filed with registration statement of Public Service Enterprise Group Incorporated under the Securities Act of 1933, No. 33-2935 filed January 28, 1986, relating to PSE&G's plan to form a holding company as part of a corporate restructuring.

(p) Filed with registration statement of PSE&G under the Securities Act of 1933, No. 33-13209 filed April 9, 1987, relating to the registration of \$575,000,000 First and Refunding Mortgage Bonds pursuant to Rule 415.

## ENTERPRISE

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
3a	(o)	3a	(o)	3a	Certificate of Incorporation Public Service Enterprise Group Incorporated
3b	(e)	3b	(e)	3b	Copy of By-Laws of Public Service Enterprise Group Incorporated, as in effect May 1,1987
3c	(e)	3c	(e)	3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987
4a(1)	(f)	B-1	(c)	4b(1) 2/18/81	Indenture between PSE&G and Fidelity Union Trust Company, (now First Fidelity Bank, National Association), as Trustee, dated August 1, 1924, securing First and Refunding Mortgage Bonds Indentures between PSE&G and First Fidelity Bank, National Association, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	(i)	7(1a)	(c)	4b(2) 2/18/81	April 1, 1927
4a(3)	(k)	2b(3)	(c)	4b(3) 2/18/81	June 1, 1937
4a(4)	(k)	2b(4)	(c)	4b(4) 2/18/81	July 1, 1937
4a(5)	(k)	2b(5)	(c)	4b(5) 2/18/81	December 19, 1939
4a(6)	(g)	B-10	(c)	4b(6) 2/18/81	March 1, 1942
4a(7)	(k)	2b(7)	(c)	4b(7) 2/18/81	June 1, 1949
4a(8)	(k)	2b(8)	(c)	4b(8) 2/18/81	May 1, 1950
4a(9)	(k)	2b(9)	(c)	4b(9) 2/18/81	October 1, 1953
4a(10)	(k)	2b(10)	(c)	4b(10) 2/18/81	May 1, 1954
4a(11)	(j)	4b(16)	(c)	4b(11) 2/18/81	November 1, 1956
4a(12)	(k)	2b(12)	(c)	4b(12) 2/18/81	September 1, 1957
4a(13)	(k)	2b(13)	(c)	4b(13) 2/18/81	August 1, 1958
4a(14)	(k)	2b(14)	(c)	4b(14) 2/18/81	June 1, 1959

Exhibit Number					
This Filing	Previous Filing				
	Commission			Exchanges	
4a(15)	(k)	2b(15)	(c)	4b(15) 2/18/81	September 1, 1960
4a(16)	(k)	2b(16)	(c)	4b(16) 2/18/81	August 1, 1962
4a(17)	(k)	2b(17)	(c)	4b(17) 2/18/81	June 1, 1963
4a(18)	(k)	2b(18)	(c)	4b(18) 2/18/81	September 1, 1964
4a(19)	(k)	2b(19)	(c)	4b(19) 2/18/81	September 1, 1965
4a(20)	(k)	2b(20)	(c)	4b(20) 2/18/81	June 1, 1967
4a(21)	(k)	2b(21)	(c)	4b(21) 2/18/81	June 1, 1968
4a(22)	(k)	2b(22)	(c)	4b(22) 2/18/81	April 1, 1969
4a(23)	(k)	2b(23)	(c)	4b(23) 2/18/81	March 1, 1970
4a(24)	(k)	2b(24)	(c)	4b(24) 2/18/81	May 15, 1971
4a(25)	(k)	2b(25)	(c)	4b(25) 2/18/81	November 15, 1971
4a(26)	(k)	2b(26)	(c)	4b(26) 2/18/81	April 1, 1972
4a(27)	(a)	2 3/29/74	(c)	4b(27) 2/18/81	March 1, 1974
4a(28)	(a)	2 10/11/74	(c)	4b(28) 2/18/81	October 1, 1974
4a(29)	(a)	2 4/6/76	(c)	4b(29) 2/18/81	April 1, 1976
4a(30)	(a)	2 9/16/76	(c)	4b(30) 2/18/81	September 1, 1976
4a(31)	(k)	2b(31)	(c)	4b(31) 2/18/81	October 1, 1976
4a(32)	(a)	2 6/29/77	(c)	4b(32) 2/18/81	June 1, 1977
4a(33)	(l)	2b(33)	(c)	4b(33) 2/18/81	September 1, 1977
4a(34)	(a)	2 11/21/78	(c)	4b(34) 2/18/81	November 1, 1978
4a(35)	(a)	2 7/25/79	(c)	4b(35) 2/18/81	July 1, 1979

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
4a(36)	(m)	2d(36)	(c)	4b(36) 2/18/81	September 1, 1979 (No. 1)
4a(37)	(m)	2d(37)	(c)	4b(37) 2/18/81	September 1, 1979 (No. 2)
4a(38)	(a)	2 12/3/79	(c)	4b(38) 2/18/81	November 1, 1979
4a(39)	(a)	2 6/10/80	(c)	4b(39) 2/18/81	June 1, 1980
4a(40)	(a)	2 8/19/81	(a)	2 8/19/81	August 1, 1981
4a(41)	(b)	4e 4/29/82	(b)	4e 5/5/82	April 1, 1982
4a(42)	(a)	2 9/17/82	(a)	2 9/20/82	September 1, 1982
4a(43)	(a)	2 12/21/82	(a)	2 12/21/82	December 1, 1982
4a(44)	(d)	4(ii) 7/26/83	(d)	4(ii) 7/27/83	June 1, 1983
4a(45)	(a)	4 8/19/83	(a)	4 8/19/83	August 1, 1983
4a(46)	(d)	4(ii) 8/14/84	(d)	4(ii) 8/17/84	July 1, 1984
4a(47)	(d)	4(ii) 11/2/84	(d)	4(ii) 11/9/84	September 1, 1984
4a(48)	(b)	4(ii) 1/4/85	(b)	4(ii) 1/9/85	November 1, 1984 (No. 1)
4a(49)	(b)	4(ii) 1/4/85	(b)	4(ii) 1/9/85	November 1, 1984 (No. 2)
4a(50)	(a)	2 8/2/85	(a)	2 8/2/85	July 1, 1985
4a(51)	(c)	4a(51) 2/11/86	(c)	4a(51) 2/11/86	January 1, 1986
4a(52)	(a)	2 3/28/86	(a)	2 3/28/86	March 1, 1986
4a(53)	(a)	2(a) 5/1/86	(a)	2(a) 5/1/86	April 1, 1986 (No. 1)
4a(54)	(a)	2(b) 5/1/86	(a)	2(b) 5/1/86	April 1, 1986 (No. 2)
4a(55)	(p)	4a(55) 4/9/87	(p)	4a(55) 4/9/87	March 1, 1987
4a(56)	(a)	4 8/17/87	(a)	4 8/17/87	July 1, 1987 (No. 1)

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
4a(57)	(d)	4 11/13/87	(d)	4 11/20/87	July 1, 1987 (No. 2)
4a(58)	(a)	4 5/17/88	(a)	4 5/18/88	May 1, 1988
4a(59)	(a)	4 9/27/88	(a)	4 9/28/88	September 1, 1988
4a(60)	(a)	4 7/25/89	(a)	4 7/26/89	July 1, 1989
4a(61)	(a)	4 7/25/90	(a)	4 7/26/90	July 1, 1990 (No. 1)
4a(62)	(a)	4 7/25/90	(a)	4 7/26/90	July 1, 1990 (No. 2)
4a(63)	(a)	4 7/1/91	(a)	4 7/2/91	June 1, 1991 (No. 1)
4a(64)	(a)	4 7/1/91	(a)	4 7/2/91	June 1, 1991 (No. 2)
4a(65)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 1)
4a(66)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 2)
4a(67)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 3)
4a(68)	(a)	4 2/27/92	(a)	4 2/28/92	February 1, 1992 (No. 1)
4a(69)	(a)	4 2/27/92	(a)	4 2/28/92	February 1, 1992 (No. 2)
4a(70)	(a)	4 6/17/92	(a)	4 6/11/92	June 1, 1992 (No. 1)
4a(71)	(a)	4 6/17/92	(a)	4 6/11/92	June 1, 1992 (No. 2)
4a(72)	(a)	4 6/17/92	(a)	4 6/11/92	June 1, 1992 (No. 3)
4a(73)	(a)	4 2/2/93	(a)	4 2/2/93	January 1, 1993 (No.1)
4a(74)	(a)	4 2/2/93	(a)	4 2/2/93	January 1, 1993 (No. 2)
4a(75)	(a)	4 3/17/93	(a)	4 3/18/93	March 1, 1993
4a(76)	(b)	4 5/27/93	(a)	4 5/28/93	May 1, 1993
4a(77)	(a)	4 5/25/93	(a)	4 5/25/93	May 1, 1993 (No. 2)

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
4a(78)	(a)	4 5/25/93	(a)	4 5/25/93	May 1, 1993 (No. 3)
4a(79)	(b)	4 12/1/93	(b)	4 12/1/93	July 1, 1993
4a(80)	(a)	4 8/3/93	(a)	4 8/3/93	August 1, 1993
4a(81)	(b)	4 12/1/93	(b)	4 12/1/93	September 1, 1993
4a(82)	(b)	4 12/1/93	(b)	4 12/1/93	September 1, 1993 (No. 2)
4a(83)	(b)	4 12/1/93	(b)	4 12/1/93	November 1, 1993
4a(84)	(a)	4 2/3/94	(a)	4 2/14/94	February 1, 1994
4a(85)	(a)	4 3/15/94	(a)	4 3/16/94	March 1, 1994 (No. 1)
4a(86)	(a)	4 3/15/94	(a)	4 3/16/94	March 1, 1994 (No. 2)
4a(87)	(d)	4 11/8/94	(d)	4 12/2/94	May 1, 1994
4a(88)	(d)	4 11/8/94	(d)	4 12/2/94	June 1, 1994
4a(89)	(d)	4 11/8/94	(d)	4 12/2/94	August 1, 1994
4a(90)	(d)	4 11/8/94	(d)	4 12/2/94	October 1, 1994 (No. 1)
4a(91)	(d)	4 11/8/94	(d)	4 12/2/94	October 1, 1994 (No. 2)
4a(92)	(a)	4 1/26/96	(a)	4 1/26/96	January 1, 1996 (No. 1)
4a(93)	(a)	4 1/26/96	(a)	4 1/26/96	January 1, 1996 (No. 2)
4b	(h)	7(12)	(c)	4c(1) 2/18/81	Indenture between PSE&G and Federal Trust Company, as Trustee (Midlantic National Bank, Successor Trustee) dated July 1, 1948, providing for 6% Debenture Bonds due 1998
4c	(l)	2c(8)	(c)	4c(8) 2/18/81	Indenture between PSE&G and The Chase Manhattan Bank (National Association), as Trustee, dated August 15, 1971, providing for 7¾% Debenture Bonds due 1996

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
4d	(b)	4 12/1/93	(b)	4 12/1/93	Indenture of Trust between PSE&G and The Chase Manhattan Bank (National Association), as Trustee, providing for Secured Medium-Term Notes dated July 1, 1993
4e(1)	(c)	2/23/95	(c)	2/23/95	Indenture between PSE&G and First Fidelity Bank, National Association, as Trustee, dated November 1, 1994, providing for Deferrable Interest Subordinated Debentures in Series
4e(2)	(a)	9/11/95	(a)	9/11/95	Supplemental Indenture between PSE&G and First Fidelity Bank, National Association, as Trustee, dated September 11, 1995 providing for Deferrable Interest Subordinated Debentures, Series B
9					Inapplicable
10a(1)	(c)	10c(1) 3/17/82	(c)	10c(1) 3/19/82	Directors' Deferred Compensation Plan
10a(2)	(c)	10c(2) 3/17/82	(c)	10c(2) 3/19/82	Officers' Deferred Compensation Plan
10a(3)	(c)	10c(3) 3/17/82	(c)	10c(3) 3/19/82	Supplemental Death Benefits Plan for officers
10a(4)	(c)	10c(4) 3/17/82	(c)	10c(4) 3/19/82	Description of additional retirement benefits for certain officers
10a(5)(i)	(c)	10b(5) 3/31/83	(c)	10b(5) 4/8/83	Limited Supplemental Death Benefits and Retirement Plan
10a(5)(ii)	(c)	10a(5)(ii) 2/25/94	(c)	10a(5)(ii) 3/1/94	Limited Supplemental Benefits Plan for Certain Employees
10a(6)(i)	(c)	10a(6) 3/10/87	(c)	10a(6) 4/16/87	Description of additional retirement benefits for certain officers
10a(6)(ii)	(c)	10a(6)(1) 3/30/90	(c)	10a(6)(1) 3/30/90	Description of additional retirement benefits for certain officers
10a(6)(iii)	(c)	10a(6)(2) 3/30/92	(c)	10a(6)(2) 4/27/92	Description of additional retirement benefits for a certain officer
10a(7)	(o)	10g	(o)	10g	Management Incentive Compensation Plan
10a(8)	(c)	10a(8) 3/30/89	(c)	10a(8) 4/18/89	Long-Term Incentive Plan
10a(9)	(c)	10a(9) 3/30/89	(c)	10a(9) 4/18/89	Public Service Enterprise Group Incorporated Pension Plan for Outside Directors
10a(10)	(c)	10a(11) 2/10/93	(c)	10a(11) 2/11/93	Letter Agreement with E. James Ferland dated April 16, 1986

Exhibit Number				
This Filing	Previous Filing			
	Commission		Exchanges	
10a(11) (c)	10a(12) 2/10/93	(c)	10a(12) 2/11/93	Letter Agreement with Paul H. Way dated March 28, 1988
10a(12) (c)	10a(13) 2/10/93	(c)	10a(13) 2/11/93	Letter Agreement with Thomas M. Crimmins, Jr. dated April 5, 1989
10a(13) (c)	10a(15) 2/10/93	(c)	10a(15) 2/11/93	Letter Agreement with Robert C. Murray dated December 17, 1991
10a(14) (c)	10a(14) 2/26/94	(c)	10a(14) 3/9/94	Letter Agreement with Patricia A. Rado dated March 24, 1993
10a(15) (c)	10a(15) 2/23/95	(c)	10a(15) 2/23/95	Letter Agreement, as amended, with Leon R. Eliason dated September 14, 1994
10a(16) (d)	10a(15) 8/14/95	(d)	10a(15) 8/14/95	Letter Agreement with Louis F. Storz dated July 7, 1995
10a(17) (d)	10a(16) 8/14/95	(d)	10a(16) 8/14/95	Letter Agreement with Elbert C. Simpson dated May 31, 1995
10a(18) (d)	10a(17) 11/14/95	(d)	10a(17) 11/14/95	Letter Agreement with Alfred C. Koeppel dated August 23, 1995
10a(19)				Directors' Stock Plan
10a(20)				Mid Career Hire Supplemental Retirement Plan
10a(21)				Retirement Income Reinstatement Plan
11				Inapplicable
12				Computation of Ratios of Earnings to Fixed Charges
13				Inapplicable
16				Inapplicable
18				Inapplicable
21				Subsidiaries of the Registrant
22				Inapplicable
23				Independent Auditors' Consent
24				Inapplicable
27				Financial Data Schedule
28				Inapplicable
99				Inapplicable

**PSE&G**

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
3a(1)	(b)	3a 8/28/86	(b)	3a 8/29/86	Restated Certificate of Incorporation of PSE&G, effective May 1, 1986
3a(2)	(c)	3a(2)	(c)	3a(2) 4/10/87	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act
3a(3)	(a)	3(a)3 2/3/94	(a)	3(a)3 2/14/94	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock (\$100 Par) as a series of the Preferred Stock
3a(4)	(a)	3(a)4 2/3/94	(a)	3(a)4 2/14/94	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock (\$100 Par) as a series of Preferred Stock
3a(5)	(a)	3(a)5 2/3/94	(a)	3(a)5 2/14/94	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock (\$100 Par) and the 6.75% Cumulative Preferred Stock — \$25 Par as series of Preferred Stock
3b					Copy of By-Laws of PSE&G, as in effect September 1, 1994
4a(1)	(f)	B-1	(c)	4b(1) 2/18/81	Indenture between PSE&G and Fidelity Union Trust Company, (now First Fidelity Bank, National Association), as Trustee, dated August 1, 1924, securing First and Refunding Mortgage Bond Indentures between PSE&G and First Fidelity Bank, National Association, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	(i)	7(1a)	(c)	4b(2) 2/18/81	April 1, 1927
4a(3)	(k)	2b(3)	(c)	4b(3) 2/18/81	June 1, 1937
4a(4)	(k)	2b(4)	(c)	4b(4) 2/18/81	July 1, 1937
4a(5)	(k)	2b(5)	(c)	4b(5) 2/18/81	December 19, 1939

Exhibit Number				
This Filing	Previous Filing			
	Commission	Exchanges		
4a(6)	(g) B-10	(c) 4b(6) 2/18/81		March 1, 1942
4a(7)	(k) 2b(7)	(c) 4b(7) 2/18/81		June 1, 1949
4a(8)	(k) 2b(8)	(c) 4b(8) 2/18/81		May 1, 1950
4a(9)	(k) 2b(9)	(c) 4b(9) 2/18/81		October 1, 1953
4a(10)	(k) 2b(10)	(c) 4b(10) 2/18/81		May 1, 1954
4a(11)	(j) 4b(16)	(c) 4b(11) 2/18/81		November 1, 1956
4a(12)	(k) 2b(12)	(c) 4b(12) 2/18/81		September 1, 1957
4a(13)	(k) 2b(13)	(c) 4b(13) 2/18/81		August 1, 1958
4a(14)	(k) 2b(14)	(c) 4b(14) 2/18/81		June 1, 1959
4a(15)	(k) 2b(15)	(c) 4b(15) 2/18/81		September 1, 1960
4a(16)	(k) 2b(16)	(c) 4b(16) 2/18/81		August 1, 1962
4a(17)	(k) 2b(17)	(c) 4b(17) 2/18/81		June 1, 1963
4a(18)	(k) 2b(18)	(c) 4b(18) 2/18/81		September 1, 1964
4a(19)	(k) 2b(19)	(c) 4b(19) 2/18/81		September 1, 1965
4a(20)	(k) 2b(20)	(c) 4b(20) 2/18/81		June 1, 1967
4a(21)	(k) 2b(21)	(c) 4b(21) 2/18/81		June 1, 1968
4a(22)	(k) 2b(22)	(c) 4b(22) 2/18/81		April 1, 1969
4a(23)	(k) 2b(23)	(c) 4b(23) 2/18/81		March 1, 1970
4a(24)	(k) 2b(24)	(c) 4b(24) 2/18/81		May 15, 1971
4a(25)	(k) 2b(25)	(c) 4b(25) 2/18/81		November 15, 1971
4a(26)	(k) 2b(26)	(c) 4b(26) 2/18/81		April 1, 1972

Exhibit Number				
This Filing	Previous Filing			
	Commission	Exchanges		
4a(27)	(a) 2 3/29/74	(c) 4b(27) 2/18/81		March 1, 1974
4a(28)	(a) 2 10/11/74	(c) 4b(28) 2/18/81		October 1, 1974
4a(29)	(a) 2 4/6/76	(c) 4b(29) 2/18/81		April 1, 1976
4a(30)	(a) 2 9/16/76	(c) 4b(30) 2/18/81		September 1, 1976
4a(31)	(k) 2b(31)	(c) 4b(31) 2/18/81		October 1, 1976 <sup>1</sup>
4a(32)	(a) 2 6/29/77	(c) 4b(32) 2/18/81		June 1, 1977
4a(33)	(l) 2b(33)	(c) 4b(33) 2/18/81		September 1, 1977
4a(34)	(a) 2 11/21/78	(c) 4b(34) 2/18/81		November 1, 1978
4a(35)	(a) 2 7/25/79	(c) 4b(35) 2/18/81		July 1, 1979
4a(36)	(m) 2d(36)	(c) 4b(36) 2/18/81		September 1, 1979 (No. 1)
4a(37)	(m) 2d(37)	(c) 4b(37) 2/18/81		September 1, 1979 (No. 2)
4a(38)	(a) 2 12/3/79	(c) 4b(38) 2/18/81		November 1, 1979
4a(39)	(a) 2 6/10/80	(c) 4b(39) 2/18/81		June 1, 1980
4a(40)	(a) 2 8/19/81	(a) 2 8/19/81		August 1, 1981
4a(41)	(b) 4e 4/29/82	(b) 4e 5/5/82		April 1, 1982
4a(42)	(a) 2 9/17/82	(a) 2 9/20/82		September 1, 1982
4a(43)	(a) 2 12/21/82	(a) 2 12/21/82		December 1, 1982
4a(44)	(d) 4(ii) 7/26/83	(d) 4(ii) 7/27/83		June 1, 1983
4a(45)	(a) 4 8/19/83	(a) 4 8/19/83		August 1, 1983
4a(46)	(d) 4(ii) 8/14/84	(d) 4(ii) 8/17/84		July 1, 1984
4a(47)	(d) 4(ii) 11/2/84	(d) 4(ii) 11/9/84		September 1, 1984

Exhibit Number					
This Filing	Previous Filing				
	Commission		Exchanges		
4a(48)	(b)	4(ii) 1/4/85	(b)	4(ii) 1/9/85	November 1, 1984 (No. 1)
4a(49)	(b)	4(ii) 1/4/85	(b)	4(ii) 1/9/85	November 1, 1984 (No. 2)
4a(50)	(a)	2 8/2/85	(a)	2 8/2/85	July 1, 1985
4a(51)	(c)	4a(51) 2/11/86	(c)	4a(51) 2/11/86	January 1, 1986
4a(52)	(a)	2 3/28/86	(a)	2 3/28/86	March 1, 1986
4a(53)	(a)	2(a) 5/1/86	(a)	2(a) 5/1/86	April 1, 1986 (No. 1)
4a(54)	(a)	2(b) 5/1/86	(a)	2(b) 5/1/86	April 1, 1986 (No. 2)
4a(55)	(p)	4a(55) 4/9/87	(p)	4a(55) 4/9/87	March 1, 1987
4a(56)	(a)	4 8/17/87	(a)	4 8/17/87	July 1, 1987 (No. 1)
4a(57)	(d)	4 11/13/87	(d)	4 11/20/87	July 1, 1987 (No. 2)
4a(58)	(a)	4 5/17/88	(a)	4 5/18/88	May 1, 1988
4a(59)	(a)	4 9/27/88	(a)	4 9/28/88	September 1, 1988
4a(60)	(a)	4 7/25/89	(a)	4 7/26/89	July 1, 1989
4a(61)	(a)	4 7/25/90	(a)	4 7/26/90	July 1, 1990 (No. 1)
4a(62)	(a)	4 7/25/90	(a)	4 7/26/90	July 1, 1990 (No. 2)
4a(63)	(a)	4 7/1/91	(a)	4 7/2/91	June 1, 1991 (No. 1)
4a(64)	(a)	4 7/1/91	(a)	4 7/2/91	June 1, 1991 (No. 2)
4a(65)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 1)
4a(66)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 2)
4a(67)	(a)	4 12/2/91	(a)	4 12/3/91	November 1, 1991 (No. 3)
4a(68)	(a)	4 2/27/92	(a)	4 2/28/92	February 1, 1992 (No. 1)

Exhibit Number				
This Filing	Previous Filing			
	Commission		Exchanges	
4a(69)	(a)	4 2/27/92	(a)	4 2/28/92 February 1, 1992 (No. 2)
4a(70)	(a)	4 6/17/92	(a)	4 6/11/92 June 1, 1992 (No. 1)
4a(71)	(a)	4 6/17/92	(a)	4 6/11/92 June 1, 1992 (No. 2)
4a(72)	(a)	4 6/17/92	(a)	4 6/11/92 June 1, 1992 (No. 3)
4a(73)	(a)	4 2/2/93	(a)	4 2/2/93 January 1, 1993 (No. 1)
4a(74)	(a)	4 2/2/93	(a)	4 2/2/93 January 1, 1993 (No. 2)
4a(75)	(a)	4 3/17/93	(a)	4 3/18/93 March 1, 1993
4a(76)	(b)	4 5/27/93	(a)	4 5/28/93 May 1, 1993
4a(77)	(a)	4 5/25/93	(a)	4 5/25/93 May 1, 1993 (No. 2)
4a(78)	(a)	4 5/25/93	(a)	4 5/25/93 May 1, 1993 (No. 3)
4a(79)	(b)	4 12/1/93	(b)	4 12/1/93 July 1, 1993
4a(80)	(a)	4 8/3/93	(a)	4 8/3/93 August 1, 1993
4a(81)	(b)	4 12/1/93	(b)	4 12/1/93 September 1, 1993
4a(82)	(a)	4 12/1/93	(a)	4 12/1/93 September 1, 1993 (No. 2)
4a(83)	(b)	4 12/1/93	(b)	4 12/1/93 November 1, 1993
4a(84)	(a)	4 2/3/94	(a)	4 2/14/94 February 1, 1994
4a(85)	(a)	4 3/15/94	(a)	4 3/16/94 March 1, 1994 (No. 1)
4a(86)	(a)	4 3/15/94	(a)	4 3/16/94 March 1, 1994 (No. 2)
4a(87)	(d)	4 11/8/94	(d)	4 12/2/94 May 1, 1994
4a(88)	(d)	4 11/8/94	(d)	4 12/2/94 June 1, 1994
4a(89)	(d)	4 11/8/94	(d)	4 12/2/94 August 1, 1994

Exhibit Number					
This Filing	Previous Filing				
		Commission		Exchanges	
4a(90)	(d)	4 11/8/94	(d)	4 12/2/94	October 1, 1994 (No. 1)
4a(91)	(d)	4 11/8/94	(d)	4 12/2/94	October 1, 1994 (No. 2)
4a(92)	(a)	4 1/26/96	(a)	4 1/26/96	January 1, 1996 (No.1)
4a(93)	(a)	4 1/26/96	(a)	4 1/26/96	January 1, 1996 (No.2)
4b(1)	(h)	7(12)	(c)	4c(1) 2/18/81	Indenture between PSE&G and Federal Trust Company, as Trustee, (Midlantic National Bank, Successor Trustee) dated July 1, 1948, providing for 6% Debenture Bonds due 1998
4b(2)	(l)	2c(8)	(c)	4c(8) 2/18/81	Indenture between PSE&G and the Chase Manhattan Bank (National Association), as Trustee, dated August 15, 1971, providing for 7¾% Debenture Bonds due 1996
4b(3)	(b)	4 12/1/93	(b)	4 12/1/93	Indenture of Trust between PSE&G and The Chase Manhattan Bank (National Association), as Trustee, providing for Secured Medium-Term Notes dated July 1, 1993
4b(4)	(b)	2/23/95	(c)	2/23/95	Indenture between PSE&G and First Fidelity Bank, National Association, as Trustee, dated November 1, 1994, providing for Deferrable Interest Subordinated Debentures in Series
4b(5)	(a)	4b(5)	(a)	4b(5)	Supplemental Indenture between PSE&G and First Fidelity Bank, National Association, as Trustee, dated September 11, 1995 providing for Deferrable Interest Subordinated Debentures in Series B
9					Inapplicable
10a(1)	(c)	10c(1) 3/17/82	(c)	10c(1) 3/19/82	Directors' Deferred Compensation Plan
10a(2)	(c)	10c(2) 3/17/82 2/25/94	(c)	10c(2) 3/19/82 3/1/94	Officers' Deferred Compensation Plan  Supplemental Benefits Plan for Certain Employees
10a(3)	(c)	10c(3) 3/17/82	(c)	10c(3) 3/19/82	Supplemental Death Benefits Plan for officers
10a(4)	(c)	10c(4) 3/17/82	(c)	10c(4) 3/19/82	Description of additional retirement for certain officers
10a(5)(i)	(c)	10b(5) 3/31/83	(c)	10b(5) 4/8/83	Limited Supplemental Death Benefits and Retirement Plan
10a(5)(ii)	(c)	10a(5)(ii)	(c)	10a(5)(ii)	Limited Supplemental Benefits Plan for Certain Employees

Exhibit Number					
This Filing	Previous Filing				
	Commission		Exchanges		
10a(6)(i)	(c)	10a(6) 3/10/87	(c)	10a(6) 4/16/87	Description of additional retirement benefits for certain officers
10a(6)(ii)	(c)	10a(6)(1) 3/30/90	(c)	10a(6)(1) 3/30/90	Description of additional retirement benefit for certain officers.
10a(6)(iii)	(c)	10a(6)(2) 3/30/92	(c)	10a(6)(2) 4/27/92	Description of additional retirement benefit for a certain officer.
10a(7)	(o)	10g	(o)	10g	Management Incentive Compensation Plan
10a(8)	(c)	10a(8) 3/30/89	(c)	10a(8) 4/18/89	Long-Term Incentive Plan
10a(9)	(c)	10a(9) 3/30/89	(c)	10a(9) 4/18/89	Public Service Enterprise Group Incorporated Pension Plan for Outside Directors
10a(10)	(c)	10a(9) 2/10/93	(c)	10a(9) 2/11/93	Letter Agreement with E. James Ferland dated April 16, 1986
10a(11)	(c)	10a(10) 2/10/93	(c)	10a(10) 2/11/93	Letter Agreement with Thomas M. Crimmins, Jr. dated April 5, 1989
10a(12)	(c)	10a(12) 2/10/93	(c)	10a(12) 2/11/93	Letter Agreement with Robert C. Murray dated December 17, 1991
10a(13)	(c)	10a(13) 2/26/94	(c)	10a(13) 3/9/94	Letter Agreement with Patricia A. Rado dated March 24, 1993.
10a(14)	(c)	10a(14) 2/23/95	(c)	10a(14) 2/23/95	Letter Agreement, as amended, with Leon R. Eliason dated September 14, 1994
10a(15)	(d)	10a(15) 8/14/95	(d)	10a(15) 8/14/95	Letter Agreement with Louis F. Storz dated July 7, 1995
10a(16)	(d)	10a(16) 8/14/95	(d)	10a(16) 8/14/95	Letter Agreement with Elbert C. Simpson dated May 31, 1995
10a(17)	(d)	10a(17) 11/14/95	(d)	10a(17) 11/14/95	Letter Agreement with Alfred C. Koepppe dated August 23, 1995
10a(18)					Director Stock Plan
10a(19)					Mid Career Hire Supplemental Retirement Plan
10a(20)					Retirement Income Reinstatement Plan
11					Inapplicable
12(a)					Computation of Ratios of Earnings to Fixed Charges
12(b)					Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
13					Inapplicable
16					Inapplicable
19					Inapplicable
21					Inapplicable
23					Independent Auditors' Consent
27					Financial Data Schedule